FINAL REPORT

Strategy Roadmap for Private Power Development in Romania

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The electric power sector is one of the world's most capital intensive industries All power sectors, especially those in developing countries, require significant amounts of private capital to maintain the existing power system and to expand for future load growth In Romania, a primary objective of power sector reform and restructuring is to create a market-driven environment that attracts private investment and expands local access to capital markets The Romanian electric utility, CONEL (formerly RENEL), has begun initial preparations to facilitate the entry of private capital by forming joint venture agreements with foreign investors to help modernize existing generation assets [1] As private sector participation in the power sector increases, CONEL must develop a comprehensive IPP strategy in order to successfully operate in a more competitive environment

As the prime contractor for the United States Agency for International Development (USAID) funded Regulatory Reform and Energy Sector Restructuring Project in Central and Eastern Europe and the Baltics (contract number DHR-C-00-95-00016-00), Bechtel Consulting conducted this study to provide CONEL with a strategy roadmap which prepares for the entry of independent power production (IPP) in Romania and helps to maximize the associated benefits The development of IPP in Romania is consistent with the following USAID/Bucharest intermediate results and strategic objectives

- Establishment of a competitive electric power system (Intermediate Result 2)
- Increased level of private sector investment in the power sector (Intermediate Result 2 1)
- Creation of a more economically sustainable and environmentally sound power sector (Strategic Objective 1 5)

1 1 STUDY FINDINGS

The results of this study are based on the analysis of data collected as part of in-country field work during the period of June to October 1998 An IPP market review was conducted after interviewing local utility representatives (CONEL and its branches), international lending agencies, and private power developers [2] The economic feasibility of IPP development (i e , greenfield, inside-the-fence, and joint ventures) was evaluated by using a financial model developed by Bechtel Consulting

IPP market review and financial analysis results were used to develop recommendations for a preliminary IPP strategy for CONEL The findings of this study are summarized as follows

- Power sector market conditions

[1] July 1998 CONEL draft report *Combined Heat and Power Plants (proposals to attract private capital)*

[2] CONEL uses the term "branch to indicate a subsidiary (business entity) of the holding company Specifically, Electrica, Hidroelectrica, and Termoelectrica are each a separate branch company of CONEL

- IPP development models
- Project financing terms and return on equity hurdle rates
- IPP financial analysis results

1.1.1 Power Sector Market Conditions

To successfully develop private power projects in Romania, IPP developers will need to overcome a combination of market and institutional barriers Current Romanian power sector market conditions, which hinder IPP development, include surplus electric capacity, dispatching constraints, energy pricing subsidies, lack of provisions guaranteeing open access to the national grid, and uncertain commercial arrangements In particular, private power projects must be evaluated in the context of the following market conditions

- *Electricity supply and demand balance* Romania has an installed capacity of 18,500 MW with an estimated peak demand of 8,500 MW which is below 1989 demand levels [1]
- *Institutional requirements* IPP development is restricted by the absence of a transparent regulatory framework, including provisions guaranteeing open access to the national grid
- *Technical and operational system constraints* Power sold to the national grid by IPP facilities would only be dispatched after "must-run" requirements have been satisfied [2]
- *Electricity pricing* Current electricity tariff structures include subsidized prices that do not allow for the full recovery of costs
- *Power sector restructuring status* The uncertain framework for commercial relationships between CONEL and its branches adds layers of complexity to IPP contractual agreements

1.1.2 IPP Development Models

The fourth quarter of 1998 has been an active period for the potential development of private power projects in Romania Increased IPP activity has coincided with the Government of Romania (GoR) adoption of restructuring initiatives that unbundled power generation, transmission and distribution functions (Decisions No 364 and 365) and created a new regulatory body (Emergency Ordinance No 29) Proposed IPP development includes the construction of greenfield plants, inside-the-fence plants, and the formation of joint venture

[1] It is important to note that current installed capacity levels include power stations that are scheduled for retirement, require refurbishment, or would be considered uneconomic compared to alternative generation sources
[2] Depending on seasonal and technical conditions, ' must-run" plants in the Romanian power system include nuclear, hydro, and combined heat and power stations

agreements with CONEL Table 1-1, displayed below, summarizes IPP projects in Romania that have either been announced or are currently under development [1]

Table 1-1
IPP Development Models and Announced Projects in Romania

IPP Development Models	Announced IPP Projects
Greenfield Greenfield IPP involve the construction of new power stations primarily through build-operate-transfer (BOT) or build-own-operate (BOO) schemes	• *Bucharest North* Amoco plans to build a new plant in Bucharest, 150 MW (electric) and 130 tons per hour (steam) *Project Announcement Date* 1997
Inside-the-fence Inside-the-fence plants are developed for large industrial or commercial facilities with a sizeable demand for electricity and/or steam	• *ALRO* Announcement by Combined Energy Companies to build a 325 MW plant for a local aluminum company (ALRO) *Project Announcement Date* 1998
Joint Venture Joint venture agreements are used to develop a wide range of private power projects including the construction of new plants and the rehabilitation of existing utility-owned facilities Joint venture partners can include private and public (state-owned) companies	• *Grozavesti Power Station (Hiesenberg)* Rehabilitation of the Grozavesti power plant *Project Announcement Date* 1997 • *Brasov Power Station (VEW)* Rehabilitation of the Brasov power plant *Project Announcement Date* 1998 • *Dutch Electricity Generating Board (SEP)* \$140 million investment in new cogen plants *Project Announcement Date* 1998

Regardless of the IPP model that is employed, current project development experience in Romania highlights the importance of minimizing the following risks as part of up-front contractual agreements

- Off-take risk[2]
- Operational and management risk
- Foreign exchange risk
- Fuel supply risk

Delays experienced by Amoco in the development of the Bucharest North greenfield combined heat and power plant illustrate the difficulty of establishing off-take agreements with multiple parties (sale of both electricity and steam) Interest in inside-the-fence projects, where power and/or steam is typically sold to a single host company, is increasing as indicated by the

[1] The European Bank for Reconstruction and Development and the International Finance Corporation are also assisting CONEL with the transformation of four existing power plants into IPP pilot projects
[2] An "off-taker" is an entity that purchases power and/or steam from an IPP Off-take risk increases when IPP customers have a poor credit rating or operate in a financial/market environment that could result in non- payment

announcement of Combined Energy Companies' project at ALRO Inside-the-fence projects can capitalize on the relatively high price of power paid by industrial end-users (approximately $50/MWh) by selling electricity at a discount from current prices

Under current market conditions, establishing a joint venture with CONEL provides the most immediate method of private sector entry Partnering with CONEL offers investors added security in terms of guaranteeing an acceptable level of future power sales Joint venture agreements can also be used to capture the environmental benefits of IPP development [1] The Dutch Electricity Generating Board (SEP) plans to develop five new gas-fired cogeneration units as part of a joint venture agreement with CONEL The greenhouse gas (GHG) reductions generated by the new plants will be used to satisfy a portion of the Dutch Kyoto Protocol GHG requirements (through reduced emissions of carbon dioxide and atmospheric pollutants)

1.1 3 Project Financing Terms and Return on Equity Hurdle Rates

The recent downgrading of Romania's credit rating by Standard & Poor's (S&P) will increase project financing risk premiums for local IPP development On October 20, 1998, S&P cut Romania's long term foreign currency debt rating from B plus to B minus while the long term currency debt rating was dropped from BB to B plus Given the country's high level of credit risk, developers pursuing projects in Romania are likely to receive the following financing terms

Interest Rate Interest rates for IPP debt financing in Romania would be set according to the London Inter-Bank Offering Rate (Libor), which is approximately 5 5%, plus an added risk premium Commercial bank loans could carry an added premium of 4% to 6% while loans backed by an export credit agency (ECA) or multilateral development bank (MDB) could carry lower premiums of 2% to 3% The importance of an ECA or MDB guarantee is illustrated by the involvement of the IFC in the ALRO project and the EBRD's involvement in the Bucharest North project

Debt Repayment Terms The high level of market and credit risk in Romania will result in strict debt repayment terms for private power projects The length of loan terms is a critical factor since debt often accounts for between 70% to 80% of total project cost Under current market conditions, IPP developers in Romania could on average receive an eight year direct reduction loan assuming that the project has ECA or MDB support

Return on Equity Hurdle Rate Depending on the final project capital structure and power purchase agreement (PPA) terms, IPP developers estimate that an acceptable ROE for a project in Romania ranges from 18% to 30%

[1] Environmental benefits from IPP (under any of the development models discussed above) can be significant when the inefficiency of existing generation assets is compared to the use of new combustion turbine technology

1.1 4 IPP Financial Analysis Results

Bechtel Consulting developed a financial model to assess the economic viability of IPP under different energy payments [1] For the purposes of this study, four IPP cases were designed to approximate the size, technology, and fuel type of current private power projects in Romania [2] Figure 1-1, shown below, presents the results of analysis conducted for greenfield (Cases A to B) and inside-the-fence projects (Cases C to D) As discussed in Section 4, the financial model is also designed to conduct an analysis of joint venture projects involving the development of both new plants and the rehabilitation of existing generation units However, to assess potential joint venture projects, economic and engineering data would need to be collected for candidate plants

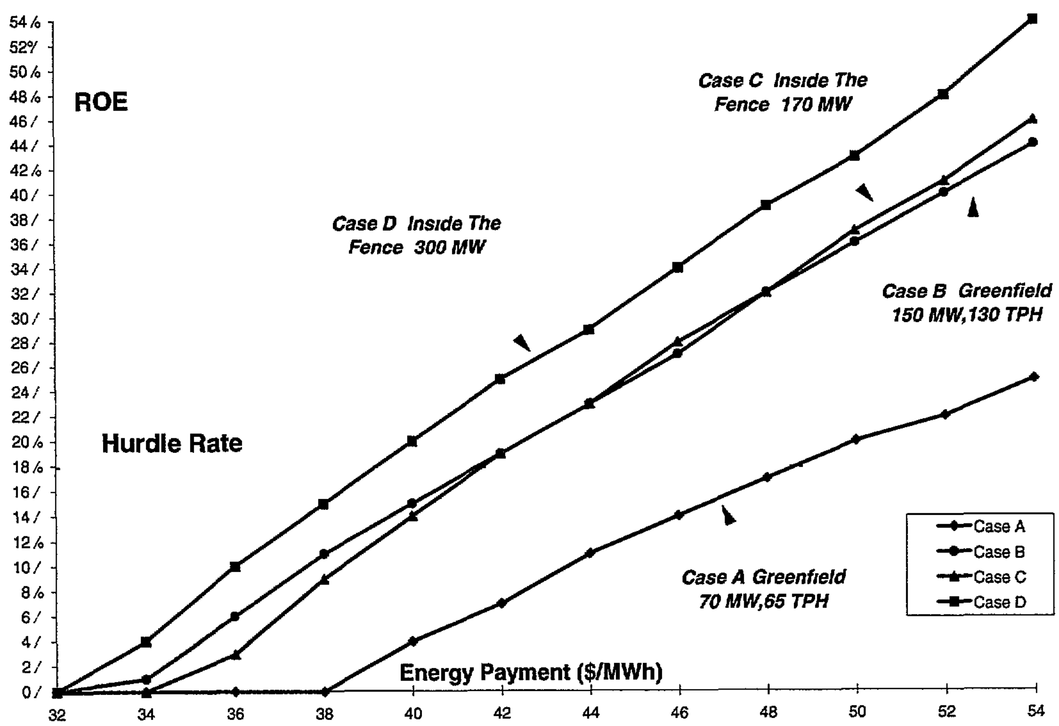

Figure 1-1 Greenfield and Inside-the-fence IPP Financial Analysis Results

Hurdle Rate Analysis The ROE can be viewed as a hurdle rate, or break-even point, for a project in the sense that if the opportunity cost of capital for an IPP developer is below the project ROE, then the project is considered to be attractive (otherwise it is rejected) For analysis conducted in this study, a ROE hurdle rate of 18% was used as a benchmark to determine the viability of potential private power projects in Romania

[1] An energy payment is the price level at which an IPP sells its output As stated in Section 4 the analysis of IPP in this study is based on a single energy payment (in $/MWh) For steam prices, an assumed price of $4/GJ was held constant The model has the flexibility to change both price levels and structure (including fixed capacity charges)
[2] Power plant data was collected to approximate the characteristics of the Bucharest North and ALRO projects

- *Greenfield (Cases A and B)* Under present market conditions, the development of greenfield IPP is unlikely Case A requires a minimum energy payment of approximately $49/MWh (at the intersection of the 18% hurdle rate) while Case B requires $41/MWh It was assumed that CONEL would accept an energy payment that approximates the marginal cost of generation ($35/MWh) [1] This leaves a significant gap between the break-even energy payment for Cases A and B and CONEL's assumed marginal cost value
- *Inside-the-fence* Inside-the-fence plants represent an immediate option for IPP development The break-even energy payment is approximately $42/MWh for Case C and $39/MWh for Case D Given that industrial end-users pay approximately $50/MWh, an IPP developer would have the pricing flexibility to provide a customer with a discount over current prices

Competitive Assessment An analysis was conducted that compares the cost of generation for each IPP case to alternative power sources For greenfield cases, where it was assumed that power would be sold to the national grid, CONEL's marginal cost of generation is used as a competitive benchmark For inside-the-fence cases, the electricity tariff paid by the industrial end-users and CONEL's marginal cost of generation are used as competitive benchmarks

- *Greenfield* The variable cost of generation for Case A is approximately $28/MWh and for Case B is $27/MWh [2] Both cases have generation costs that are below the $35/MWh threshold The low variable cost of Cases A and B indicates the potential competitiveness of greenfield options in future bidding for new capacity
- *Inside-the-fence* Case C has a variable cost of $29/MWh while the variable cost for Case D is $27/MWh This places inside-the-fence plants in a strong competitive position when compared to the current price of electricity for industrial end-users and the estimated marginal cost of generation ($35/MWh) [3]

1.2 RECOMMENDATIONS

The establishment of joint venture agreements at the Grozavesti and Brasov power plants illustrates the viability of private power development under the current market environment Given the possibility for immediate entry of IPP, CONEL and its branches should develop a strategy that optimizes the potential benefits from increased private sector participation In addition to formulating a strategy for CONEL and its branches, a coordinated plan for the entire Romanian power sector should be developed in order to accelerate the implementation of regulatory reforms, which will help remove existing barriers to IPP development A comprehensive IPP strategy should include the following elements

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[1] A marginal cost of $35/MWh was assumed based on the results of a 1998 least-cost planning study conducted for CONEL A further discussion is presented in Section 4

[2] Variable costs include fuel and variable O&M (no labor costs)

[3] A more comprehensive analysis of inside-the-fence options would also consider the impact of costs associated with the potential end-user need for stand-by or back-up power generation

- CONEL IPP strategy and business planning development
- Clarification of CONEL and branch commercial relationships
- Continued institutional development and regulatory reforms

1.2 1 CONEL IPP Strategy and Business Planning Development

With the entry of IPP, outside capital can be leveraged to meet current and future investment needs, achieving a strategic objective of restructuring To capitalize on private investment opportunities, CONEL should strengthen its internal financial analysis and investment planning capabilities as well as enhance its current business planning activities Section 5 of this study outlines an initial set of strategy recommendations for CONEL and its branches, including

- Identification of strategic objectives
- Establishment of joint venture partner criteria
- Development of internal IPP financial analysis capabilities

1 2 2 Clarification of CONEL and Branch Commercial Relationships

Although GoR Decisions No 364 and No 365 represent an important restructuring milestone, they do not clearly define the commercial roles and responsibilities of the new utility business entities Therefore, the implementation of the new holding company structure must provide power sector participants with a clear division of the organizational responsibilities between CONEL and its branches The definition of commercial relationships will remove uncertainty for investors in terms of establishing off-take agreements

1 2 3 Institutional Development and Regulatory Reform

Given that IPP typically involves the construction of facilities with an economic life exceeding 20 years, the establishment of a transparent regulatory framework that provides investors with adequate guarantees is imperative [1] In particular, continued GoR regulatory reform and restructuring efforts must include the establishment of secondary legislation that address key institutional development areas, including

- Open access provisions for electricity suppliers and producers (third-party access)
- Separation of the transmission system operator from other utility functions

[1] Although GoR Emergency Ordinance No 29 represents a critical power sector restructuring step, it does not fully address how key regulatory requirements will be implemented

- Eligibility of customers to purchase electricity directly from competitive suppliers
- PPA development that address the potential of moving towards a competitive power market

The passage of a new energy law, which is pending GoR approval, would eliminate several remaining legal and regulatory obstacles to the creation of a competitive electricity market in Romania

2 1 PROJECT BACKGROUND

Thıs work was carned out under the Unıted States Agency for Internatıonal Development (USAID) funded Regulatory Reform and Energy Sector Restructurıng Project ın Central and Eastern Europe and the Baltıcs As the project's prıme contractor, Bechtel Consultıng developed a prelımınary IPP roadmap strategy for CONEL and ıts branches [1] An economıc assessment of IPP optıons ın Romanıa was also conducted usıng a fınancıal model developed by Bechtel Consultıng to serve as an IPP strategy and busıness plannıng tool

In 1996, Bechtel Consultıng ıdentıfied a range of optıons for restructurıng the Romanıan power sector as part of Phase I project actıvıtıes Wıth the Government of Romanıa (GoR) approval of a restructurıng plan for CONEL ın July 1998, Bechtel Consultıng ınıtıated Phase II project actıvıtıes Phase II actıvıtıes ınclude assıstance to CONEL and the Mınıstry of Industry and Trade (MoIT) ın the followıng four task areas

- Assessment and analysıs of the Brasov electrıcıty dıstrıbutıon unıt
- Restructurıng ımplementatıon plan
- Development of power sector regulatıon and ımplementatıon of a natıonal electrıcıty law
- Independent power productıon (IPP) and prıvatızatıon strategy

Thıs study summarızes ınıtıal work completed ın the area of IPP strategy and busıness plannıng The prelımınary IPP strategy roadmap presented ın thıs study represents a startıng poınt ın an ıteratıve work process between USAID and CONEL IPP strategy elements should be vıewed ın the context of broader busıness plannıng actıvıtıes to be carrıed out by CONEL and ıts branches as part of ongoıng commercıalızatıon actıvıtıes

2 2 STUDY OBJECTIVES AND METHODOLOGY

Prıvate sector development of IPP can generate sıgnıficant fınancıal and operatıonal benefits for the Romanıan power sector, ıncludıng gaıns ın effıcıency, avoıded cost of new capacıty, and reduced ınvestment ın the rehabılıtatıon of exıstıng power plants However, the entry of IPP also presents CONEL wıth a new set of strategıc ıssues and busıness plannıng requırements

An IPP market revıew was conducted as part of ın-country field work durıng the perıod of June to September 1998, to ıdentıfy potentıal prıvate power optıons ın Romanıa The market revıew ıncluded ıntervıews wıth local utılıty representatıves (CONEL and branches), ınternatıonal lendıng agencıes, and prıvate power developers The economıc feasıbılıty of varıous IPP optıons (ı e , greenfield, ınsıde-the-fence, and joınt venture projects) were determıned through the use of

[1] In July 1998, the former electrıc utılıty (RENEL) was reorganızed ınto CONEL whıch ıs a new holdıng company wıth separate busıness entıtıes responsıble for carryıng out generatıon and dıstrıbutıon functıons Sectıon 3 of thıs study contaıns a more detaıled dıscussıon of the utılıty holdıng company structure

a financial model developed by Bechtel Consulting The IPP market review and financial modeling results were used to develop a preliminary IPP roadmap for CONEL, which can be incorporated into ongoing business planning activities Figure 2-2 illustrates the methodology used to complete this study and the relationship between individual IPP task work activities

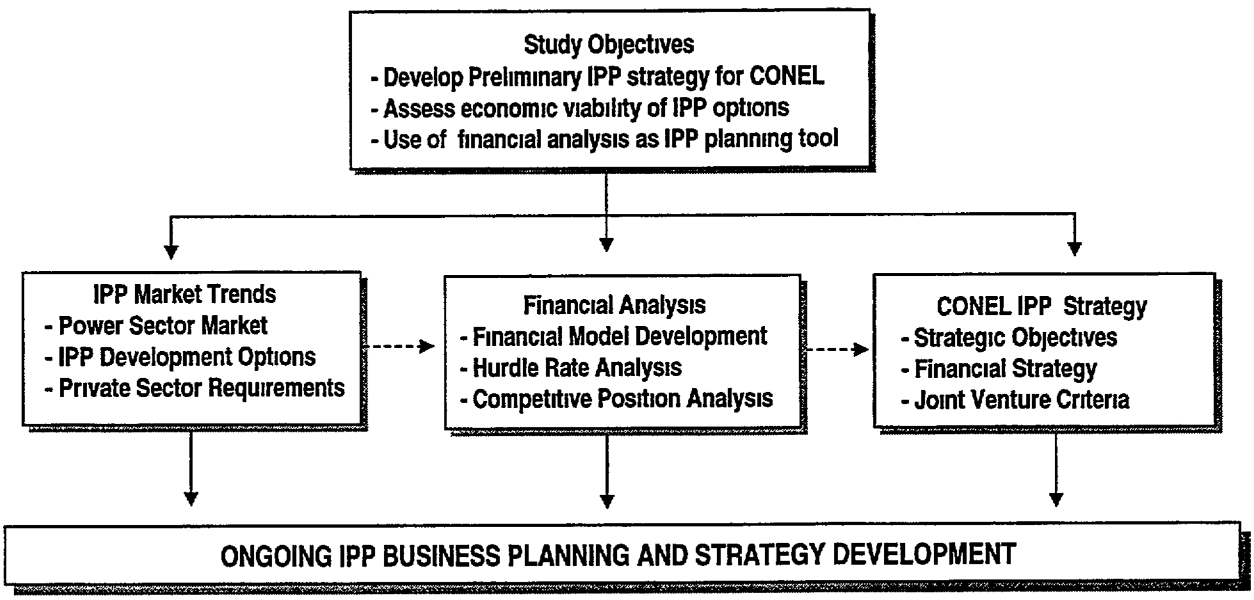

Figure 2-2 Romania IPP Roadmap Study Methodology

This study provides CONEL and its branches with a preliminary roadmap for assessing IPP development The remainder of this study is organized in the following sections

Section 3 summarizes Romania IPP market trends and discusses the connection between local private power development and the presence of market and project risks

Section 4 details the results of financial analysis of Romanian IPP options using a spreadsheet model developed by Bechtel Consulting An emphasis is placed on illustrating the use of the financial model as a business planning and IPP strategy tool for CONEL and its branches

Section 5 outlines preliminary IPP strategy issues and recommendations Initial strategy and business planning recommendations include the identification of strategic objectives, establishment of joint venture partner criteria, and the development of IPP financial planning capabilities

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An understanding of the driving forces of private power development in Romania is a prerequisite for developing an IPP business planning strategy for CONEL and its branches To evaluate Romanian IPP market trends, Bechtel Consulting conducted interviews with CONEL and its branches, private power developers, and financial lending organizations Results of other Bechtel-led tasks in the area of restructuring, regulatory reform, and commercialization were also incorporated in assessing the IPP market [1] The interdependence of the following IPP market trends is evaluated

- Romania IPP options and prospects
- Power sector market conditions
- Project risks
- Project financing terms and acceptable return on equity levels

The remainder of this section illustrates the link between IPP options, power sector market conditions, and private power project risks The relationship between these market trends, local project financing terms, and the minimum acceptable return on equity (ROE) for an IPP developer in Romania is also discussed

3 1 ROMANIA IPP OPTIONS AND PROSPECTS

Bechtel Consulting conducted a detailed review of the IPP options that are currently being pursued in Romania

- Greenfield projects (Bucharest North Project, Amoco)
- Inside-the-fence projects (ALRO project, Combined Energy Companies)
- Joint venture projects (rehabilitation projects at the Grosavesti and Brasov power plants, development of new cogeneration plants with the Netherlands Cogen consortium)
- Multilateral Development Bank IPP assistance (European Bank for Reconstruction and Development and International Finance Corporation pilot projects)

3.1.1 Greenfield Projects

Greenfield IPP involves the construction of new power stations primarily through build-operate-transfer (BOT) or build-own-operate (BOO) project schemes In a BOT project, a private entity receives a franchise to finance, build, and operate a power project for a designated time period

[1] In addition to the IPP activities (Workplan Task 4), the Bechtel team is providing assistance to CONEL and the MoIT in the following areas Brasov Distribution Assessment (Task 1), Restructuring Implementation (Task 2), and the Implementation of the Electricity Law and Development of Power Sector Regulation (Task 3)

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after which ownership reverts to the host government or utility In a BOO project, a private entity finances and builds the project but maintains ownership indefinitely The primary off-take source for the output of a greenfield plant is the local utility, however, power and/or steam can also be sold to nearby industrial or commercial end-users

One greenfield project currently being pursued is Amoco's Bucharest North combined heat and power plant (CHP) which would be sized to produce approximately 150 MW electric and 130 tons per hour of steam Potential sources for the plant's output include CONEL, the municipality of Bucharest, and nearby industrial end-users However, obtaining off-take agreements from multiple sources is an ongoing obstacle to the Bucharest North project development

3 1 2 Inside-the-Fence Projects

Inside-the-fence plants are generally developed for large industrial or commercial facilities with a sizeable demand, which allows projects to capture significant economies of scale [2] Inside-the-fence plants primarily service the demand of a single host company but, depending on local regulatory provisions, also sell some output back to the utility

The recent announcement made by Combined Energy Companies to build a 325 MW gas-fired project for the state-owned aluminum company, ALRO, is evidence of both the interest and feasibility of inside-the-fence projects For CONEL industrial customers, paying an average of $50MWh, inside-the-fence projects may offer a long-term economic solution for meeting their energy needs

3.1.3 Joint Ventures Agreements

Joint venture agreements can be used to develop a wide range of power projects including the construction of new plants and the rehabilitation of existing facilities Joint ventures recently established between CONEL and foreign investors have helped finance the rehabilitation of both the Grosavesti and Brasov power plants The formation of joint ventures represents an opportunity to finance the rehabilitation of existing power plants through private investment under current market conditions

In November 1998, the Dutch Electricity Generating Board (SEP) announced its plans to develop new cogeneration units as part of a joint venture agreement with CONEL [3] A Dutch consortium will invest $140 million to construct five new plants that will be located in Arad, Timisoara, Cluj-Napoca, Iasi, and Govora [4] The plants will run on natural gas that will be imported from the

[2] There is an increasing trend towards the development of "total energy management" systems that employ small gas or diesel-fired turbines (1 to 2 MW) to serve the commercial and industrial sector

[3] "Kyoto protocol sends Dutch to Romania", *The Business Review*, November 16 to 22, 1998

[4] The Dutch consortium indicated that the plants could have a potential start-up date in 2001

Netherlands The development of these plants will help satisfy the Netherlands' greenhouse gas (GHG) reduction obligations under Kyoto Protocol, indicating the possibility of further IPP development by using clean development mechanisms [5]

3.1 4 Multilateral Development Bank IPP Pilot Programs

The European Bank for Reconstruction and Development (EBRD) and the International Finance Corporation (IFC) are both in the process developing "pilot" programs that will provide assistance to CONEL in the transformation of four existing generation plants into IPP facilities The IFC is providing CONEL with advisory services focused on the establishment of two potential IPP pilot projects The EBRD has signed a memorandum of understanding with CONEL to develop two additional IPP pilot projects EBRD activities are likely to include funding for up-front technical assistance as well as financing of the potential IPP pilot projects at a later stage

3.2 POWER SECTOR MARKET CONDITIONS

The Romanian power sector has historically been organized as a centrally planned and vertically integrated state monopoly In an effort to move towards a more market driven environment, the GoR passed a restructuring plan which separates power generation, transmission, and distribution functions, achieving a critical first step towards power sector restructuring [6] Although the GoR restructuring plan is an essential element for attracting private investment, the limited development of IPP in Romania reflects the need for further structural and regulatory changes

Current Romanian power sector market conditions, which hinder IPP development, include surplus electric capacity, dispatching constraints, energy pricing subsidies, lack of secondary legislation (regulatory provisions), and uncertain commercial arrangements Private investors evaluating IPP options would assess the viability of projects in terms of the following power market conditions

- Electricity supply and demand balance
- Institutional requirements
- Technical and operational system constraints
- Pricing
- Power sector restructuring

[5] The use of clean development mechanisms, including joint implementation, offer countries a cost-effective method of meeting environmental obligations associated with the reduction of greenhouse gases

[6] In July 1998, the GoR passed Decisions No 364 and 365 which call for the formation of a new holding company structure for power generation, transmission and distribution operations

3 2.1 Electricity Supply and Demand Balance

With an installed capacity of roughly 18,500 MW and an estimated peak demand of 8,500 MW, the Romanian market contains surplus power generation capacity Current electricity demand is below 1989 levels, reflecting the continued contraction of the Romanian economy [7] However, it is important to note that current installed capacity levels include power stations that are scheduled for retirement, power stations that require refurbishment, and power stations that would be considered uneconomic when compared to alternative generation sources CONEL recently conducted a least cost planning study that estimated that the Romanian power system would require new capacity additions by 2003 [8]

IPP Market Implication In the absence of regulatory reform (see institutional requirements section below), the surplus capacity situation should limit the need for development of greenfield IPP prior to the year 2003 During this interim period (present to the year 2003), likely modes of IPP development will include inside-the-fence plants and joint venture projects between CONEL and private sector entities

3.2 2 Institutional Requirements

The GoR exerts direct control over the regulation and development of the power sector through the Ministry of Industry and Trade (MoIT) which has historically served as both owner and regulator of CONEL However, the GoR's adoption of emergency ordinance No 29 created an independent regulatory agency that will be responsible for regulating the market for electricity and heat Although the emergency ordinance grants the new agency with broad regulatory powers, further legal and regulatory provisions are needed to attract private capital for IPP development [9] In particular, private investors will want to know the substance of secondary legislation as well as how the agency will operate in practice

IPP Market Implication Without the continued implementation of regulatory reforms, the entry of IPP into Romania will be limited In particular, regulatory and legal provisions are needed to guarantee competitive electricity suppliers open access to the national grid (third-party access) The GoR should expand upon emergency ordinance No 29 by establishing a regime that ensures IPP developers that regulatory decisions will be made free from undue political interference and in an objective, transparent, and non-discriminatory manner

3 2 3 Technical and Operational System Constraints

The Romanian power system contains several types of generation units that are designated as "must-run" facilities, including hydroelectric plants, the Cernavoda nuclear station, and

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[7] The International Monetary Fund (IMF) estimates that Romanian GDP will drop by roughly 5% in 1998

[8] *Least Cost Power and Heat Generation Capacity Development*, 1998 study by EdF, SEP, and Tractebel

[9] A summary of the GoR Emergency Ordinance No 29 is presented in Appendix B

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combined heat and power units Must-run facilities require mandatory dispatching of electricity and, depending on technical and seasonal conditions, these facilities can account for approximately 70% of total system demand [10]

In addition, the national electricity grid encounters some transmission congestion problems when transmitting power from the Craiova region to northern points of the country (including Transylvania and Moldavia)

IPP Market Implication In general, IPP facilities that sell electricity to the national grid would only be dispatched after all must-run requirements have been satisfied Given current electricity supply and demand conditions, the operation of must-run facilities would restrict potential IPP power sales Developers of private power plants would evaluate Romanian electricity supply and demand levels in order to assess the sensitivity of a project's economic viability under different dispatching scenarios

In terms of transmission congestion problems, IPP developers would potentially encounter favorable dispatching scenarios if new plants were located in areas north of Craiova (i e , avoiding congestion areas could offer a slight advantage because there would be fewer dispatching constraints)

3 2.4 Pricing

The Romanian power sector contains energy tariffs with multiple cross-subsidies Industrial prices have historically subsidized residential prices while electricity prices have subsidized steam prices A recent MoIT tariff proposal addresses the issue of cross subsidies by seeking lower electricity prices for industrial end-users ($45/MWh) while increasing the price of power for residential customers

IPP Market Implication An electricity tariff structure that includes subsidized prices and does not allow for the full recovery of costs hinders the development of private power in Romania IPP development requires the presence of strong and stable cash flows, which provide investors with a return commensurate with associated project risks and a guarantee of sufficient debt coverage for lenders

3 2 5 Power Sector Restructuring

The passage of GoR decisions No 364 and 365, which unbundled utility operations and formed a new holding company structure, represents an important milestone in power sector reform However, the GoR decisions do not outline the commercial roles and responsibilities ("rules of the game") for the operation of these new business entities In addition, recent restructuring developments have provided potential IPP developers with little clarification regarding the

[10] This percentage could vary significantly according to seasonal conditions and prevailing demand requirements

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timing of moving towards a competitive power market (power pool formation) Table 3-1 illustrates the new organizational structure of CONEL

Table 3-1
Romanian Electric Utility Holding Company Structure

Company Entity	Responsibility
CONEL *(Corporate Center)*	CONEL is the corporate center and operates the transmission and dispatch system The network consists of 220, 400, and 450 kV lines that are controlled by eight units (five regional dispatching centers and three new transmission centers)
Electrica *(Branch company)*	Electrica carries out electric distribution activities through 42 regional units (41 counties plus Bucharest) that were organized into a new company responsible for the operation of low and medium voltage lines (110 kV and below)
Termoelectrica *(Branch company)*	The former Group for Generation of Electrical and Thermal Energy (GPEET) was separated into two new branches Termoelectrica was established as a separate business unit responsible for the operation of thermal power plants
Hidroelectrica *(Branch company)*	The remaining portion of GPEET, Hidroelectrica, was established as a subsidiary responsible for the operation of hydroelectric power plants

IPP Market Implication The uncertain framework for commercial relationships between and with CONEL and its branches dampens the potential for IPP development by adding layers of complexity to off-take agreements Given the transitional nature of the Romanian power sector restructuring, IPP power purchase agreements (PPAs) would also need to address the potential of moving towards a competitive power market

Brazil offers an example of IPP transitional contract agreements In Brazil, IPP developers purchasing existing generation assets receive an eight year initial contract that guarantees the sale of 100% of available output for years one through five For each following year (years six through eight), guaranteed sales drop by 25% In year nine, the IPP facility must sell all of its output in the open market

3 3 PROJECT RISKS

The limited development of IPP in Romania is in part due to a range of in-country project risks IPP developers and lending agencies indicated in interviews conducted by Bechtel Consulting that the following risk areas need to be addressed as part of up-front contractual negotiations

- *Off-take (market) Risk* IPP developers need to mitigate the risk associated with the sale of electricity and/or steam Developers often require local government support (often through the Ministry of Finance) to secure off-take obligations involving state agencies and public sector companies Amoco's experience with the Bucharest North project demonstrates the importance of securing credible off-take agreements Addressing key credit issues as part of long term PPAs can decrease off-take risk [11] Credible PPAs are essential to obtaining favorable project financing terms

- *Operational and Management Risks* Since the generation of power and/or steam is the sole source of future cash flow for IPP, financial lending agencies may require that agreements be reached regarding the management and operational control of a plant
- *Foreign Exchange Risk* Given the potential for regional fluctuations in exchange rates, private investors would require currency convertibility and protection Foreign exchange risk could be limited by allowing for a pass-through of exchange rate fluctuations as part of IPP pricing agreements
- *Fuel Supply Risk* Financial lending agencies providing debt to IPP developers would insist on the demonstration of access to a reliable supply of fuel In general, IPP developers would need to obtain long term fuel supply agreements as well as back-up fuel options to obtain project financing Fuel supply risk is of particular importance for gas-fired projects in Romania given the currently limited number of import options (primarily Russia)

3 4 PROJECT FINANCING TERMS AND ACCEPTABLE RETURN ON EQUITY

Nearly two-thirds of all capital raised for private power projects is provided through project financing mechanisms [12] Establishing strong contractual agreements that mitigate local power sector and project development risks is essential to securing favorable financing terms The current level of power sector and project development risk in Romania is illustrated in the following project financing terms and required ROE for IPP and other large infrastructure projects

Return on Equity Based on discussions with international IPP developers, an acceptable ROE for projects in Romania could range from 18% to 30% (depending on the level of project risks and the structure of debt)

Interest Rate Based on discussions with money center banks and multilateral lending agencies, the likely interest rate for IPP debt financing is the London Inter-bank Offering Rate (Libor), which is approximately 5 5%, plus 4% to 6% for commercial bank loans and Libor plus 2% to 3% for multilateral agency loans The recent downgrading of Romania's credit rating by Standard & Poor's (S&P) would increase current interest rate risk premiums On October 20, 1998, S&P cut Romania's long term foreign currency debt rating from B plus to B minus while its long term currency debt was dropped from BB to B plus

[11] The Bechtel team is providing assistance with the development of "model" power purchase agreements though the law firm of Pierce Atwood

[12] World Bank *Power Project Financing Experience in Developing Countries* January 1998

Loan Terms Power project financing loan terms (number of years in which debt must be repaid) is, on average, more restrictive for projects proposed in nations with high country and market risk levels The length of loan terms is a critical factor of IPP success because debt often accounts for between 70 to 80 percent of the total project cost

Debt Reserve Funds Lending agencies would also be likely to require an IPP developer in Romania to use a debt reserve fund Debt reserve funds protect lenders from excess risk exposure by requiring IPP developers to deposit an amount equivalent to the estimated first year project principal repayment The end result is a higher total initial cost of IPP development, which is often passed through to end-users in the form of higher energy payments

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4 1 IPP STRATEGY APPLICATIONS

As the Romanian power sector transitions to a competitive market environment, CONEL and its branches should incorporate financial analysis into IPP strategic and business planning activities in order to

- Assess independent power project returns and private investor hurdle rates
- Conduct competitive assessments of IPP options compared to existing generation assets
- Establish appropriate energy pricing agreements

This section summarizes the results of the financial analysis conducted to assess four example IPP cases [1] Specifically, the economic viability of two greenfield plants and two inside-the-fence plants were evaluated under different project scenarios A discussion of the scenarios developed for each case illustrates how financial modeling can be used to assess potential IPP performance under different economic and engineering parameters

4.2 SCENARIO DEVELOPMENT

The financial model calculates an after tax return on equity (ROE), net present value (NPV), and payback period for a range of private power projects [2] The model generates multiple scenario analysis of projects by varying engineering, economic, and financial assumptions Scenarios can be used to facilitate an assessment of IPP options by making assumptions about the driving forces of project economic viability, including financing terms, capital costs, plant efficiency, pricing structure (energy payment and/or capacity payment), and capital structure

4.2.1 Engineering Assumptions

Engineering and technical data were collected for four plants (Cases A to D), which were designed to approximate the size, technology, and fuel type of current private power projects in Romania [3] Data were collected for both combined heat and power (CHP) and electricity only plants As illustrated below in Table 4-2-1, Cases B and D resemble the characteristics of the ALRO and Bucharest North projects [4] Cases A and C were designed to allow for the analysis of IPP with a lower electric (megawatts, MW) and thermal output (tons per hour, TPH) [5]

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[1] A summary of model outputs (cash flow statements) is presented in Appendix C

[2] For this analysis the ROE and internal rate of return (IRR) for a project are equivalent because the IRR is based on cash flows that include debt repayment Therefore, in subsequent text, IPP project IRRs are referred to as ROE

[3] Plant diagrams and engineering and cost data for Cases A to D are displayed in Appendix D

[4] Cases B and D approximate the characteristics of the Bucharest North and the ALRO projects However, these cases are solely used to illustrate the methodology in which an assessment of IPP options could be conducted

[5] The output of plants in Cases A and C were set to equal approximately half the output generated by Cases B and D

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Table 4-2-1
Plant Configuration

Case	Electric Capacity	Steam Capacity	Installed Cost ($/kW)	Heat Rate (kJ/kWh)[1]	Plant Configuration
A	70 MW	65 TPH	$610	8,432	1 x Gas Turbine, 1 x Steam Turbine, and 1 x HRSG (Siemens Equipment)
B	150 MW	130 TPH	$423	8,285	1 x Gas Turbine, 1 x Steam Turbine, and 1 x HRSG (GE equipment)
C	170 MW	0 TPH	$410	7,216	1 x Gas Turbine, 1 x Steam Turbine, and 1 x HRSG (GE Equipment)
D	300 MW	0 TPH	$373	6,866	1 x Gas Turbine, 1 x Steam Turbine, and 1 x HRSG (GE Equipment)

Natural gas was used in all cases based on international IPP technology and development trends The minimal environmental impact associated with natural gas use compared to other locally available fuels is also consistent with the GoR's stated objective of meeting European Union (EU) environmental requirements

4 2 2 Economic and Financial Assumptions

Bechtel Consulting's discussions with international lending agencies, investment organizations, and private power developers were used to refine economic and financial model assumptions for each IPP case An emphasis was placed on evaluating the current project financing environment for large infrastructure projects in Romania In particular, likely capital structures (split of project debt and equity), sources of debt (potential use of multilateral financing and export credit arrangements), and loan terms were assessed

The financial model allows for pricing agreements to be structured as a single variable payment (in $/MWh) or as a multiple payment scheme that uses both a variable energy payment and a fixed capacity charge (in $/MW/Year) Fixed charges are typically designed to cover capital costs, debt service, taxes, return on investment, and fixed O&M Variable energy charges are designed to cover fuel, and variable O&M (including labor)

For the purposes of IPP cases evaluated in this study, the use of a single variable energy payment was assumed Table 4-2-2, below, details the assumptions used to develop Cases A to D Each financial model input can be changed to test the sensitivity of IPP performance to different variables

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[1] Plant heat rates for Cases A and B do not reflect efficiency gains from CHP generation

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Table 4-2-2
Project Structure, Economic, and Financial Assumptions

Model Input	Greenfield Plants	Inside-the-Fence
Project Structure	• Build-Own-Operate	• Build-Operate-Transfer
Off-take Agreement	• Electricity Utility CONEL/branch • Steam Industrial end-user • 20 year long-term contract	• Electricity end-user host company • 20 year long-term contract
Pricing Structure	• Energy Payment in $/MWh • Steam Payment in $/GJ	• Energy Payment in $/MWh
Capital Structure	• 70% Debt • 30% Equity	• 70% Debt • 30% Equity
Loan Term	• 8 Years	• 8 Years
Interest Rate	• 10% nominal interest rate	• 10% nominal interest rate
Debt Reserve Fund	• Equal to 1st year principal payment	• Equal to 1st year principal payment
Grace Period	• 1st year principal repayment	• 1st year principal repayment
Fuel price	• Natural gas $0 12/m^3 (World Bank data for Russian gas imports)	• Natural gas $0 12/m^3 (World Bank data for Russian gas imports)

As discussed in Section 3, project financing terms vary according to IPP market trends The project terms listed above in Table 4-2-2 reflect both local market conditions and private power industry averages A key assumption for both greenfield and inside-the-fence cases is the use of strong, up-front, contractual arrangements (including PPAs) that minimize risks [1] An additional assumption is that the debt sources for IPP in Romania would include a guarantee or credit enhancement from ECAs or from a multilateral development bank MDBs [2]

4 3 FINANCIAL ANALYSIS RESULTS

Financial analysis results of greenfield and inside-the-fence cases are divided into project hurdle rate, and competitive position analysis

Project Hurdle Rate This analysis involves a comparison of the ROE for an individual project to an internal benchmark of required return on investment (typically a developer's cost of capital) The ROE is as a break-even point for a project in the sense that if the opportunity cost of capital for an IPP developer is below the project ROE, then the project is considered to be attractive For the purposes of this analysis, the hurdle rate was set at 18% with the assumption that project risks have been mitigated through the use of long-term contracts

Competitive Position This analysis compares the cost of generation for an IPP option to alternative power sources For greenfield cases, where it is assumed that power would be sold to

[1] The Bechtel team is reviewing PPA development options as part of ongoing assistance provided by Pierce Atwood
[2] This is consistent with both Romania and international IPP market trends A 1998 *World Bank* study reports that over 60% of private power project financing between 1994 to 1996 involved the use ECAs and MDBs

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the national grid, the marginal cost of generation is the appropriate benchmark Based on least cost planning estimates, CONEL's current marginal cost is $22/MWh This low marginal cost level reflects the current situation of excess power generation capacity that exists in Romania However, as the need for investment in new capacity increases, CONEL's marginal cost of power will rise to approximately $35/MWh [1] Given that the economic life of plants assessed in this study could exceed 20 years, it was assumed that IPP energy payments would be based on a marginal cost value that better reflects the cost of future capacity additions [2]

For inside-the-fence cases, the current electricity tariff paid by the industrial host company as well as the CONEL marginal cost of generation are used as a competitive yardsticks [3]

4 3 1 Greenfield Options: Hurdle Rate Analysis

Figure 4-3-1 illustrates the financial viability of Cases A and B for a range of energy payments (keeping the steam price constant at $4/GJ) The approximate break-even energy payment is $49/MWh for Case A and $41/MWh for Case B (at the intersection of the 18% ROE hurdle rate)

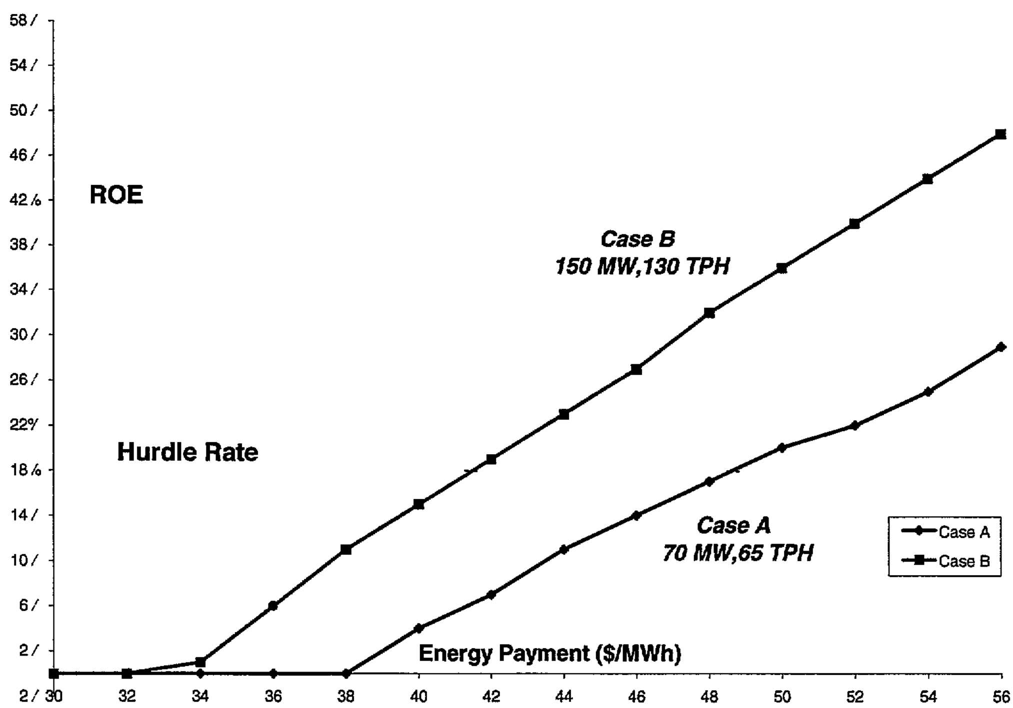

Figure 4-3-1: Greenfield IPP Results

[1] *Least Cost Power and Heat Generation Capacity Development Electricity and Heat Tariff Study* June 1998

[2] The calculation of detailed marginal cost values is beyond the scope of this study A complete analysis would include an assessment of future power system operating and expansion costs

[3] A comprehensive evaluation of inside-the-fence projects would also consider the cost associated with potential back-up power needs (either from the local utility or through the use of a stand-by generator)

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4 3 2 Greenfield Options: Competitive Position

Based on the results of this analysis, Case A would require a minimum energy payment of $49/MWh while Case B would require $41/MWh to be financially attractive This leaves a significant gap between the required IPP developer energy payment and the assumed marginal cost of CONEL generation However, it is important to note that the variable cost of production for plants used in Cases A and B is below the $35/MWh threshold The variable cost for Case A is $28/MWh while Case B is $27/MWh [1] Fuel, which accounts for almost 90% of total variable costs, is a key determinant of a project's competitive position

4 3 3 Inside-the-Fence Options: Hurdle Rate Analysis

Similar to the hurdle rate analysis for Cases A and B, the financial model was used to calculate an after tax ROE for Cases C and D under different energy payment levels Figure 4-3-3 illustrates that the approximate break-even energy payment for Case C is $42/MWh (at the intersection of the 18% ROE hurdle rate) while the break-even point for Case D is $39/MWh

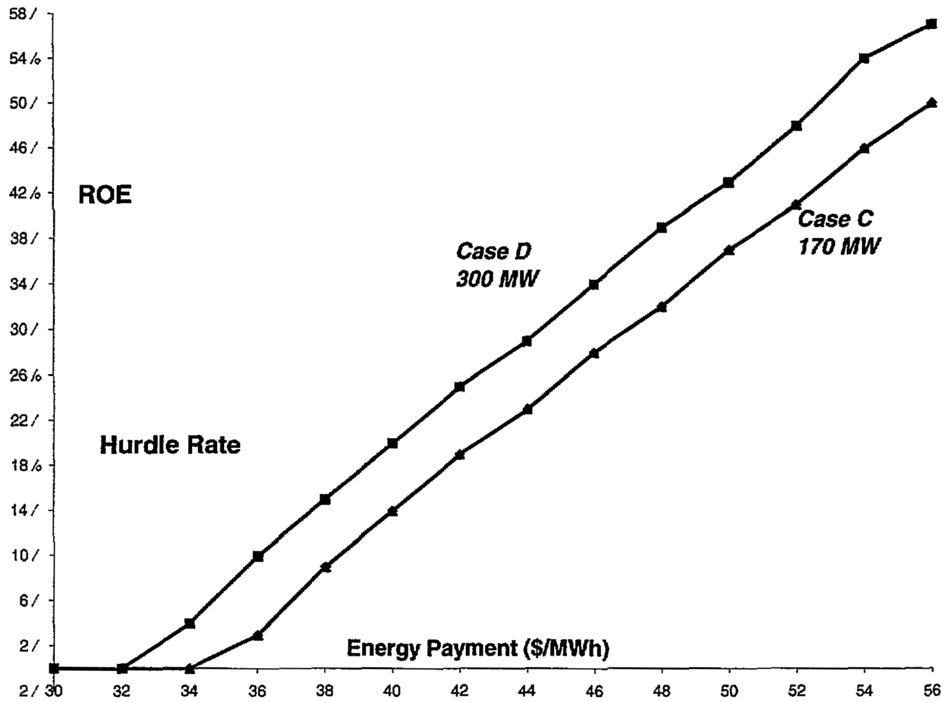

Figure 4-3-3 Inside-the-Fence Plant Results

4 3 4 Inside-the-Fence Options: Competitive Position

Given that industrial customers pay $50/MWh, an IPP developer would have the pricing flexibility to provide an industrial customer with a discount over current prices However, the

[1] Variable costs include fuel and variable O&M (no labor costs)

recent MoIT proposal to lower electricity prices for industrial customers to approximately $45/MWh would provide IPP developers with less pricing flexibility In terms of variable cost performance, both cases are competitive with CONEL's assumed marginal cost of generation at $35/MWh Case C has an estimated variable cost of $29/MWh while the variable cost for Case D is $27/MWh

4.4 JOINT VENTURE OPTIONS: FINANCIAL ANALYSIS OUTLINE

The financial analysis of joint venture options (similar to the analysis of greenfield and inside-the-fence cases) can be conducted based on further input and data provided by CONEL and its branches The financial model is designed to conduct an analysis of joint venture projects involving the development of both new power plants and the rehabilitation of existing generation units To assess potential joint venture projects, economic and engineering data would need to be collected for candidate plants This includes the clarification of key joint venture project elements, including

- The equity and debt role of each joint venture participant
- The percentage distribution of profits (free cash flow) and losses [1]
- Data for rehabilitation projects would need to reflect the potential increase in plant output (annual MWh), operating efficiency, operation and maintenance costs, and overall reliability

Although the analysis would require the development of new assumptions, the steps required to assess the economic viability of joint venture options would be similar to the analysis conducted for greenfield and inside-the-fence cases

[1] Free cash flow is what remains after a company has paid all its costs of production, lenders, and has made any capital expenditures required to keep its facilities in working order

The establishment of an IPP strategy for CONEL and its branches should be guided by strategic objectives that are consistent with the direction of regulatory change in the Romanian power sector The implementation of regulatory reforms will complement CONEL's IPP strategy development and business planning by removing existing institutional barriers to private power development This section outlines initial IPP strategy recommendations, including

- Identification of strategic objectives
- Establishment of joint venture partner criteria
- Development of an IPP financial strategy
- Institutional development and regulatory reform

Strategy recommendations reflect the market trends, IPP development options, and power sector market conditions that were identified in Section 3

5 1 IDENTIFICATION OF STRATEGIC OBJECTIVES

As the role of the private sector increases, CONEL and its branches must develop a strategy to not only successfully operate in a more competitive environment, but to optimize the potential benefits from IPP entry Table 5-1, displayed below, contains a list of strategic objectives for IPP entry based on international development experience The objectives are segmented by the Romanian IPP development options presented in Section 3

Table 5-1
Summary of CONEL Strategic Objectives for IPP Entry

Strategic Objective	Greenfield IPP	Inside-the-Fence	Joint Venture
Attraction of Private Capital	✓ through BOO or BOT schemes	✓ through private capital/technology	✓ private investment in joint venture project
Increased Efficiency and Productivity	✓ entry of new efficient technology	✓ if the plant is a cogeneration unit	✓ through installation of new equipment
Avoided Costs	✓ avoided cost of capacity additions	✓ avoided capacity, service remote areas	✓ avoided cost of rehabilitation/additions
Extended Operating Life of Existing Assets			✓ through private capital/technology
Increased Level of Competition	✓ new competitive generation source	✓ new competitive generation source	✓ improved generation competitor
Completion of Partially Built Plants	✓ through private sector investment		✓ through private sector investment
Technology Transfer			✓ potential transfer in joint ventures deals

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Meeting the strategic objectives listed above in Table 5-1 will help CONEL and its branches maximize profitability through improved productivity and efficiency Enhanced operational performance should also be viewed as a strategy to limit the erosion of market share from inside-the-fence IPP development by existing industrial customers

Achieving efficiency gains from private sector participation in the power sector will also help generate environmental benefits associated with the reduction of greenhouse gas (GHG) emissions Romania has committed itself to reducing carbon dioxide (CO_2) emissions by eight percent from 1989 levels during the period of 2008 to 2012 By increasing the overall productivity and efficiency of the power sector, CONEL and its branches can play a central role in helping Romania meet its GHG reduction target

The identification of strategic objectives should be incorporated into business planning activities Established strategic objectives need to be communicated both internally (CONEL and branch personnel) and externally (private sector, lending organizations, and regulatory body) Progress towards meeting objectives should be monitored at both the holding company and branch level based on adherence to performance indicators The following list of initial performance indicators can serve as a yardstick to measure progress towards IPP-related strategic objectives

- Annual private sector investment in the Romanian power sector
- Avoided annual capital expenditures (as a result of joint-ventures or other IPP options)
- Efficiency gains (rehabilitation of individual units or system-wide gains)
- Number of private/foreign investors in the power sector

5.2 DEVELOPMENT OF JOINT VENTURE PARTNER CRITERIA

The establishment of joint ventures with foreign investors at the Grozavesti and Brasov power plants illustrate the viability of joint ventures agreements under the current market environment Given that these type of agreements represent an immediate option for IPP entry, CONEL and its branches should develop a set of criteria to assess joint venture partners as part of their regular business planning activities A portfolio of prospective partners should be developed by assessing candidates with the following criteria

Provision of Capital A primary objective of joint venture projects is to attract private capital Therefore, CONEL should seek outside investors with an established track record for financing and developing international power projects A partner should also be able to arrange for a project financing package that includes an outside equity contribution

Project Experience CONEL should partner with companies that have successfully developed projects of a similar size, fuel type, and technology to that of the project under consideration

Regional Experience The level of regional experience should also be used as a selection criteria for joint venture partners Specifically, CONEL should seek a partner with extensive private power project experience in either Central and Eastern Europe or the former Soviet Union

Expertise in a Technology The development of joint ventures may also require the installation of a specific technology or type of power systems equipment In this instance, CONEL should identify a partner company that specializes in either the manufacture, operation, or development of projects using the required technology

Operation and Maintenance Experience The development of some joint venture projects may require that CONEL have an outside group provide operation and maintenance (O&M) services In this case, CONEL should either partner with a project developer that has extensive O&M experience or attempt to contract for third-party O&M services

5 3 DEVELOPMENT OF AN IPP FINANCIAL STRATEGY

The entry of IPP will necessitate the formulation of a strategy for addressing the financial requirements of private power development Therefore, CONEL should develop a strategy to assess key financial issues of private power projects

5 3 1 Joint Venture Financial Strategy Issues

CONEL has stated that a primary objective of joint venture agreements is to finance the rehabilitation of existing plants and the completion of partially constructed plants The following financial strategy elements should be reviewed as part of an assessment of joint venture agreements between CONEL and private investors

Cost of Financing CONEL should assess whether or not entering into a joint venture is the most cost effective method of financing the retrofit of existing generation assets This will require an ongoing assessment of other available sources of financing (debt, trade finance, etc)

Valuation of Assets Private investors will require that an independent valuation be conducted of any assets that CONEL plans to contribute as equity in a joint venture project In accordance with international accounting standards (IAS), the Romanian economy is considered to be hyperinflationary Therefore, the use of IAS 29 is required All relevant financial statements for assets to be used as equity for a project will need to be restated for the impact of inflation [1]

[1] The Bechtel team is providing assistance to the Brasov electricity distribution company in the preparation of accounting statements that are consistent with IAS practices The results of this work were recently presented at a November 1998 conference on the *Commercialization of Electrica's Distribution Companies*

Profit Center Status CONEL must also determine if an objective of a joint venture is to have the project operate as a profit center that generates annual cash flow for the company

Allocation of Profits and Losses Joint venture partners will require the implementation of strong contractual agreements regarding profit and loss distribution Joint venture profits are typically based on the distribution of free cash flow (after tax cash flow) according to predetermined ownership percentages CONEL's ownership percentage would likely be based on the value of its equity contribution to the total value of the joint venture project However, the allocation of profits could also be established through an up-front agreement that provides one party with a guaranteed rate of return

Financial Impact of State Guarantees Depending on the proposed joint venture project, CONEL should assess the need for a state guarantee (from the Ministry of Finance) of any assets or contractual agreements This would require an assessment of the project cost with and without a state guarantee

Labor Considerations The status and value of labor used to operate an existing plant under consideration for a joint venture must also be reviewed This includes the clarification of key contractual arrangements as well as the requirements of future plant operations

5 3 2 Greenfield IPP Financial Strategy Issues

Although joint ventures represent a more immediate area of IPP activity, the importance of outlining a financial strategy for the entry of greenfield IPP will steadily increase over time CONEL should start to acquire decision-making capabilities and tools in the following areas

Investment Planning CONEL estimates that new capacity additions might be required by the year 2003 During this interim period, CONEL should accelerate the development of its capital budgeting and investment planning capabilities This includes the development of least-cost planning activities which would be required to assess greenfield IPP options in terms of other supply and demand side resources

Assessment of Energy Pricing Agreements As power sector restructuring progresses, CONEL and its branches will increasingly be called on to assess energy pricing contracts from IPP developers Evaluation of proposed prices will require the segmentation of operating costs, investment recovery, and returns that are included in an IPP energy payment

As illustrated below in Figure 5-2, the IPP financial model can also be used to segment an energy payment into variable, fixed, investment cost recovery, and "profit" components

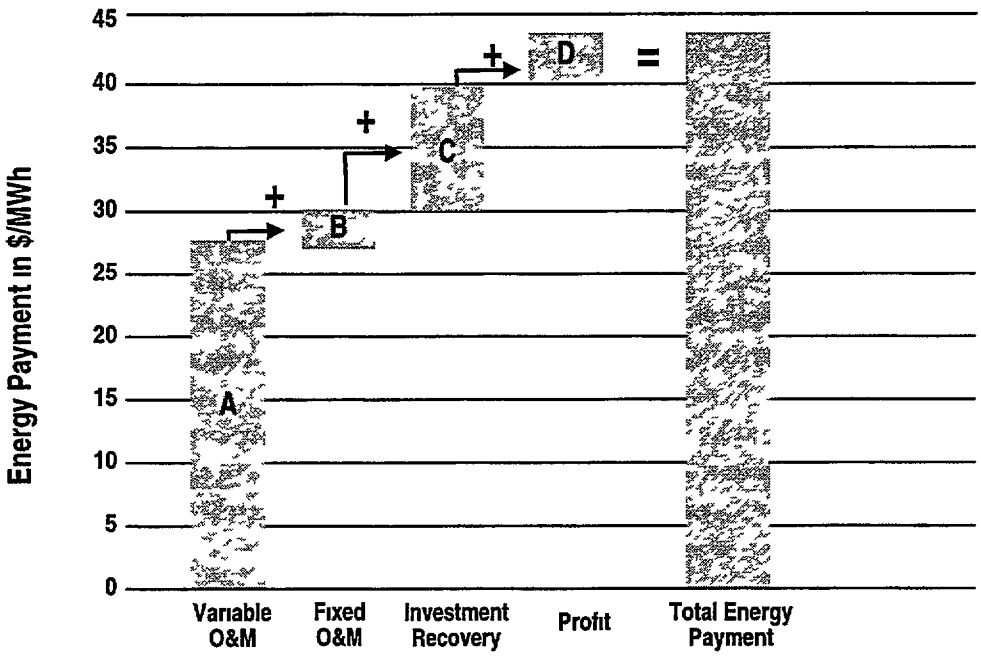

Figure 5-2 IPP Break-even Energy Payment Example

Figure 5-2 illustrates the key components of a $44/MWh break-even energy payment for a 290 MW gas-fired combined cycle plant [1] The financial model can analyze the following energy payment categories

- *Variable Costs* The portion of the energy payment that includes both the annual cost of fuel and all costs associated with plant variable operation and maintenance
- *Fixed Costs* The element of the energy payment that includes fixed operation, maintenance costs, and annual labor costs
- *Investment Recovery Costs* The portion of the energy payment necessary to cover the total initial investment cost associated with the development of the power plant
- *Profit* The difference between the energy payment and the total cost of electricity generation (sum of variable, fixed, and investment costs) This remaining portion of the energy payment can be viewed as profit to help generate an appropriate return on equity

The majority of the $44/MWh energy payment consists of variable O&M costs and investment cost recovery The inability to minimize contractual risks associated with project financing would raise the level of investment recovery (portion C), thereby raising the overall level of a proposed energy payment

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[1] The 290 MW plant is used for illustrative purposes and is based on Electric Power Research Institute Technical Assessment Guide data The financial model can also be used to segment energy payments for a range of IPP cases

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5 4 INSTITUTIONAL DEVELOPMENT

An essential element in attracting private investment is the creation of an independent regulatory body that is insulated from undue political interference and that ensures consistency and stability in the power sector [1] The GoR adoption of emergency ordinance No 29, which creates an autonomous public institution, will help Romania develop a regulatory environment that is conducive to private sector investment The GoR ordinance provides the new regulatory body with broad powers, including licensing, tariffs, eligibility for direct sales, technical standards, and dispute resolution

Ongoing regulatory reforms in Romania will need to expand upon GoR ordinance No 29 by providing private investors with additional legal and regulatory provisions that are outlined in the European Union Directive EC 92/96 Key elements of regulatory reform and institutional development that must be addressed in secondary legislation, include

- open access provisions for electricity suppliers and producers (third-party access)
- separation of the transmission system operator from other utility functions
- eligibility of customers to purchase electricity directly from competitive suppliers

[1] The Bechtel team has provided the GoR with assistance in the formation of an independent regulatory body as part of work carried out by the law firm of Pierce Atwood

Chase Manhattan Bank *Elements of Internationally Financable PPAs Presented at the Conference on Power Industry Restructuring and IPP* Seoul, Korea June 1998

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EdF, SEP, and Tractebel *Least Cost Power and Heat Generation Capacity Development*, 1998

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Government of Romania Official Gazette *Decision No 364 and 365 of 1998 Reorganization of the Electricity Public Enterprise RENEL* July, 1998

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Implementation of Restructuring of the Romanian Power Sector Assessment and Analysis of the Brasov Distribution Subsidiary Prepared by Bechtel Consulting under contract to the United Agency for International Development (USAID) December, 1998

"Kyoto protocol sends Dutch to Romania", *The Business Review* November 16 to 22, 1998

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"The Politics of Power Electricity Industry Survey" *Business Central Europe* June 1998

Standard & Poor's *Global Project Finance* September 1997

Study of Options for the Long Term Structure of the Power Sector Prepared by Bechtel Consulting under contract to USAID March 1996

World Bank *Power Project Financing Experience in Developing Countries* January 1998

U S and Foreign Commercial Service *1998 Romania Country Commercial Guide*

U S Department of Energy *Electricity Reform Abroad and U S Investment* August 19, 1998

EMERGENCY ORDINANCE

Referring to the establishment, organization and operation of the Regulation Authority in the field of energy – NRAE

On the basis of art. 114 par. (4) of the Romanian Constitution

The ROMANIAN GOVERNMENT adopts the following Emergency Ordinance

Art 1
(1) The Regulation Authority in the Energy sector is established - NRAE, a Romanian public institution with a legal statute, located in Bucharest, 3, Constantin Nacu str , sector 3
(2) NRAE is financed wholly from funds outside the budget, obtained from tariffs for granting licenses and authorisations, as well as from contributions of the economic operators, according to art 70 let c) of Law no 72/1996 regarding public finances In order to carry out its activity, materials and funds received from natural and legal persons can be used
(3) The level of tariffs and contributions provided in par (2) is settled by NRAE each year, in the conditions of the law, and are published

Art 2
(1) Taking over from the National Electricity Company – SA the goods contained in annex no 1, constitutes the patrimony of NRAE
(2) The assets of the National Electricity Company – CONEL, set up following GD 365/1998, are reduced by 1 850 000 000 ROL, corresponding to the goods taken over by NRAE
(3) Delivery and receipt of the goods provided under par (2) will take place after being recorded in a protocol concluded between the National Electricity Company SA and NRAE within 30 days after entry into force of the present Ordinance, to the value of 1 850 000 000 ROL

Art 3 NRAE creates and applies the compulsory regulation system at national level, as required by the operation of the sector and the electricity and heat market that ensures efficiency, competition, transparency and consumer protection

Art 4 NRAE is organized and operates according to its own management and operating regulations, approved by the Ministry of Industry and Trade, that co-ordinates its activity until the electricity and heat law is passed Within 30 days from entry into force of the present emergency ordinance the management and operation regulations will be drawn up

Art 5 NRAE is authorized to have the following competencies
(a) It issues and grants, suspends or withdraws authorizations and licenses for the economic operators in the electricity and heat sectors, as well as for those that will appear after opening the electricity and heat market,
(b) It establishes the criteria and methods for the calculation of tariffs and prices in the electricity and heat sector

(c) It concludes framework contracts referring to sale, purchase and supply of electricity and heat to final consumers,
(d) It decides upon the criteria to determine electricity consumers eligibility,
(e) It sets the technical and trade norms that are compulsory for the economic operators in the sector, required for the efficient and transparent operation of the national energy system,
(f) It develops and issues norms for the efficient use of electricity and heat,
(g) It makes up the misunderstandings related to the conclusion of electricity and heat supply contracts,
(h) It controls the fulfillment of its own decisions by economic operators in the electricity and heat sector and applies sanctions in case of their non-observance,
(i) It develops programs, inclusive assistance programs, approved by the Minister of Industry and Trade,
(j) It carries out any other competence lawfully provided

Art 6 NRAE's main tasks are the following

(a) It develops its Management and Operation regulations and sets out the tasks of its staff, according to lawful provisions in force,
(b) It develops the authorization and license issuing and granting system for the electricity and heat sector as well as the conditions for their suspension, withdrawal or modification
(c) It sets out lawfully the calculation approach of prices and tariffs used in the activities that are a natural monopoly, upon advice of the Competition Office, taking into account the protection of the electricity and heat consumers' interests
(d) It sets, upon advice of the Competition Office, the prices and tariffs applied to captive consumers, those practiced by the licensees of public activities and services in the electricity and heat sector, the prices and tariffs practiced between economic operators in the same sector, the tariffs for the services connected with the electricity system, transmission and distribution through the national energy system, as well as the prices and tariffs practiced for the services connected with heat production and distribution
(e) It approves the programming and dispatching regulations governing the national energy system,
(f) It approves the technical codes of the transmission and distribution networks developed by the National Electricity Company SA,
(g) It approves the framework contracts for the sale and purchase of electricity and heat between the economic operators of the sector
(h) It approves the framework contracts referring to electricity supply to captive consumers
(i) It sets out the requirements, criteria and procedures to determine eligibility of electricity consumers
(j) It develops its own methodology of follow up and control with the view to make all the electricity and heat suppliers to observe the system of prices and tariffs
(k) It develops according to the legal provisions the statement, notification and sanctioning regulations for infringement of regulations issued in the field,
(l) It develops the methods to make up the precontractual misunderstandings related to electricity and heat supply

(m)It follows up lawful conclusion of contracts between investors and authorities and is self-responsive for their protection
(n) It follows up application of quality standards in the field of the specific services in the sector and proposes their updating whenever required
(o) It submits to the Ministry of Industry and Trade measures of prevention and invalidation of the abuse of the dominant power in the market whenever infringement of regulations referring to competition and transparency on the market is found
(p) It creates a database required in its activity and for supplying information to other authorities in the development of the strategy of the electricity and heat sector, as well as in connection with foreign trade with electricity and the international practice in the field The data are published upon advice of the Minister of Industry and Trade,
(q) It trains and continuously improves NRAE staff, including support from foreign technical assistance
(r) It informs the Ministry of Industry and Trade about the activity carried out,
(s) It fulfills also any other tasks established by legal regulations

Art 7 The terms referring to *electricity sector, code, supplier, final consumer, access to the network, eligible consumer and captive electricity consumer, authorisation and license,* used in the present Ordinance have the meanings defined in Annex no 2

Art 8 NRAE is structured in specialty departments, according to their approved competence and the Management and Operation regulations

Art 9
(1) NRAE activity is managed by a president appointed by order of the Minister of Industry and Trade for a period of 5 years
(2) The President is a public officer and his quality is not compatible with any other public function or dignity, excepting the didactic activity in higher learning institutes The President is not allowed to carry out directly or through intermediate persons trade activity or to participate in the management or administration of commercial companies, autonomous state companies or cooperatives
(3) The President's mandate ceases
a) upon expiry of its duration,
b) upon resignation,
c) following decease,
d) following final impossibility to carry out the mandate, after unavailability longer than 60 consecutive days,
e) other incompatibility as provided under passage (2),
f) following revocation, due to infringement of the provisions of the present emergency ordinance or for final criminal penalty decided by the Court The authority that appointed the President can also decide upon the latter's revocation

(4) The president issues decisions in the fulfillment of his/her tasks

(5) The decisions that have a general purport for the economic operators in the field of electricity and heat are published in Romania's Official Monitor
(6) The decisions taken by the president as a consequence of the fulfillment of his/her tasks can be attacked in the administrative contentious at the Court of Appeal in Bucharest within 30 days after notification to the parties concerned or from date of their publication in Romania's Official Monitor, if they are of general interest

Art 10
(1) NRAE's President is assisted by a Consultative Council formed of 7 members appointed by order of the Ministry of Industry and Trade based upon the proposals received from the professional associations in the field of energy, the electricity and heat consumers' organisations as well as the appointed specialists of the Ministry of Industry and Trade
(2) The Consultative Council supports harmonisation of the economic operators' interest in the sector with those of electricity and heat consumers It evaluates the impact of NRAE regulations and submits proposals for their improvement, according to its Management and Operation Regulations

Art 11
(1) The staff is hired and dismissed according to NRAE's Management and Operation Regulations, with the collective labour contract and legal provisions in force The incompatibility conditions settled under art 9 paragraph (2) are also applicable to the staff
(2) The staff taken over from the National Electricity Company SA is considered transferred to NRAE and keeps their wages up to negotiation of their labour contract
(3) The collective labour contract will be negotiated and recorded with the Labour and Social Protection Directorate of the city of Bucharest within 30 days from entry into force of the present emergency ordinance

Art 12 NRAE's staff is paid in accordance with the regulations in force valid for public institutions and financed wholly from resources outside the budget

Art 13
(1) NRAE sets its own annual budget of revenues and expenses in accordance with the methodological norms established by the Ministry of Finance, which will be submitted to the Ministry of Industry and Trade
(2) The annual excess resulting from execution of NRAE's income and expense budget remains at its disposal and are used next year with the same destination

Art 14
(1) The economic operators in the sector of electricity and heat are obliged to put at the disposal of NRAE all the information required for the execution of its activities in good conditions
(2) Supply of incorrect, incomplete or wrong information is a lawful infringement and is sanctioned with a fine of 10,000,000 ROL to 25,000,000 ROL
(3) The penalty provided in paragraph (2) is applied also to legal persons

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(4) Infringement provided under paragraph (2) is stated and sanctions are applied by NRAE authorized officers
(5) The penalties provided under paragraph (2) are subjected to the provisions of Law no 32/1968 concerning statement and sanctioning of infringement, with its consequent modifications and additions

Art 15 In the fulfillment of its tasks NRAE collaborates with the Competition Council, Competition Office and the Office for the Consumers' Protection, the ministries and other specialized local authorities concerned, the energy consumers' associations, the specialised energy operators that render services in the sector, the professional associations in the electricity and heat sector, and the employers' associations

Art 16
(1) Within 4 months from entry into force of the present emergency ordinance, NRAE issues the regulations concerning granting of licenses and authorisations in the electricity and heat sector These regulations will establish the procedure and conditions required therefore
(2) Within one year after coming into force of the present emergency ordinance, NRAE will issue regulations that establish the tariffs for heat distribution and sale

Art 17 The annexes no 1 and 2 are an integral part of the present Emergency Ordinance

PRIME MINISTER
RADU VASILE

Signed also by

Minister of Industry and Trade, Radu Berceanu
Minister of Reform, President of the Reform Council, Ioan Muresan
Minister of Finance, Decebal Traian Remes
Minister of Labor and Social Protection, Alexandru Athanasiu
For State Secretary, Head of Competition Office
Constantin Prigoreanu Sub-secretary of State

The following is a list of assumptions used in the financial analysis of the four different cases evaluated in this study Cash flow results for each case are presented at the end of this section

Project Structure
- Assumed build-operate-transfer (BOT) structure with a concession period of 20 years for both greenfield and inside-the-fence cases
- Assumed that the IPP developer waived the right to any terminal value at the end of the concession period as part of BOT agreement

Loan Assumptions
- Direct reduction term loan of 8 years at an interest rate of 10%
- A one-year grace period on principal repayment was employed
- It is also assumed that the lender would require the use of a debt reserve fund
- The reserve fund amount is estimated to be equal to the principal repayment in the first year of debt service Interest rate on the reserve fund is 5%
- A financing fee of 3% was assumed

Capital Structure
All cases employ a capital structure of 70% debt and 30% equity

Depreciation
Appropriate construction costs were depreciated using a straight-line method over a period of 15 years while financing charges were depreciated over a 7 year period Depreciation charges were not assumed to be affected by currency devaluation

Import Duty
An import duty of 7% was assessed on major equipment costs

Taxes
An assumed tax rate of 35% was used for the purposes of this analysis

Escalation of Operating Costs and Revenues
All costs (fuel and operating expenses) are escalated by an annual inflation rate of 3%
Electricity and tariffs are also escalated by the same 3% rate

Discount Rate
All discount rates are assumed to be in nominal form

Initial Working Capital[1]

- Initial working capital was set equal to the following accounts receivable + inventories + operating cash - accounts payable in the first year of sales
- Days payable and accounts receivable were both assumed to be 30 days

Other Working Capital Assumptions

- Inventories were assumed to be equal to one month of fuel cost
- Operating cash was set at an initial annual level of $50,000 and was then escalated each year by 3%

Currency

Analysis was conducted in US dollars Ideally, this analysis would have been carried out in local currency allowing for a more accurate assessment of tax and depreciation However, the assessment of potential exchange rate loss/gain over a 20-year period was beyond the scope of this report Therefore, a simplifying assumption was made that purchasing power parity (PPP) between the US dollar and the Romanian lei would hold

IPP CASH FLOW ANALYSIS RESULTS

Presented in the following section is a summary of the cash flow results for the four IPP cases For each IPP case, the financial model was run using the break-even energy payment level discussed in Section 4

1) Case A - (70 MW, 65 TPH of steam)
2) Case B - (150 MW, 130 TPH of steam)
3) Case C - (300 MW)
4) Case D - (170 MW)

[1] Working capital is included in this analysis because changes in working capital are relevant to the investment decision In addition to increases in fixed assets, investments require increases in working capital items, such as inventories and receivables

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Romania IPP Assessment (inside the-fence example)
Cash Flow Statement
(Thousand Dollars)

A

Year Ending	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Plus Operating Revenues	$	$	$ 33 027	$ 34 017	$ 35,038	$ 36,089	$ 37,172	$ 38 287	$ 39 435	$ 40 618	$ 41 837
Less Operating Expenses	$	$ -	$ 22,665	$ 23 345	$ 24 045	$ 24 767	$ 25 510	$ 26,275	$ 27,063	$ 27,875	$ 28,712
Cash From Operations	$	$	$ 10 361	$ 10 672	$ 10 992	$ 11 322	$ 11,662	$ 12 012	$ 12 372	$ 12 743	$ 13 126
Plus Interest on Reserve Fund	$	$	$ 220	$ 218	$ 218	$ 218	$ 218	$ 218	$ 218	$ 218	$ 218
Less Income Taxes	$	$	$ 589	$ 697	$ 951	$ 1 223	$ 1,514	$ 1 826	$ 2 160	$ 2 840	$ 3 226
Less Total Interest Expense	$	$	$ 4 647	$ 4 647	$ 4 241	$ 3,794	$ 3 302	$ 2 761	$ 2 166	$ 1 512	$ 792
Less Total Principal Repayment	$	$	$	$ 4 064	$ 4,470	$ 4 917	$ 5 409	$ 5 950	$ 6 545	$ 7 199	$ 7 919
Less Increase in Working Capital	$	$	$	$ 72	$ 74	$ 77	$ 79	$ 81	$ 84	$ 86	$ 89
Less Change in Debt Reserve Fund	$	$	$ (44)	$	$	$	$	$	$	$	$ (4 356)
Operating Cash Flow	$	$	$ 5 389	$ 1 410	$ 1 473	$ 1 529	$ 1 575	$ 1 611	$ 1 635	$ 1 323	$ 5 673
Less Capital Cost/Sale Price	$ 30 795	$ 35 595	$	$	$	$	$ -	$	$	$	$
Net Cash Flow After Investments	$ (30,795)	$ (35 595)	$ 5 389	$ 1,410	$ 1,473	$ 1 529	$ 1 575	$ 1 611	$ 1 635	$ 1 323	$ 5 673
Plus Loan Draws	$ 21 556	$ 24,916	$	$	$	$	$	$ -	$	$	$ -
Net Cash Flow After Debt Financing	$ (9 238)	$ (10 678)	$ 5 389	$ 1 410	$ 1 473	$ 1 529	$ 1,575	$ 1,611	$ 1 635	$ 1 323	$ 5 673
Plus Equity Draws	$ 9 238	$ 10 678	$	$	$	$	$	$	$ -	$ -	$ -
Net Cash Flow For Equity Distribution	$	$	$ 5 389	$ 1 410	$ 1 473	$ 1 529	$ 1 575	$ 1 611	$ 1 635	$ 1 323	$ 5 673
Return on Equity											
Cash Available for Equity Distribution	$	$	$ 5 389	$ 1 410	$ 1 473	$ 1 529	$ 1 575	$ 1 611	$ 1 635	$ 1 323	$ 5 673
Less Equity Paid in Cash	$ 9,238	$ 10,678	$	$	$	$	$ -	$	$ -	$ -	$ -
Equity Participants Cash Flow	$ (9,238)	$ (10 678)	$ 5 389	$ 1 410	$ 1 473	$ 1 529	$ 1,575	$ 1 611	$ 1 635	$ 1,323	$ 5 673

Return on Equity	**18%**
Net Present Value @ Discount Rate	
10%	**$20,391**
12%	**$13,114**
14%	**$7,608**
Pay Back Year	-

Romania IPP Assessment (inside-the-fence example)

Cash Flow Statement

(Thousand Dollars)

A

Year Ending	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Plus Operating Revenues	$ 43 092	$ 44 385	$ 45 716	$ 47 088	$ 48 501	$ 49 956	$ 51 454	$ 52 998	$ 54 588	$ 56 226	$ 57 912	$ -
Less Operating Expenses	$ 29,573	$ 30 460	$ 31,374	$ 32,315	$ 33,285	$ 34 283	$ 35 312	$ 36 371	$ 37 462	$ 38 586	$ 39 743	$
Cash From Operations	$ 13 519	$ 13,925	$ 14 343	$ 14 773	$ 15 216	$ 15 673	$ 16 143	$ 16 627	$ 17 126	$ 17 640	$ 18 169	$
Plus Interest on Reserve Fund	$	$	$	$	$	$ -	$	$	$	$ -	$	$
Less Income Taxes	$ 3 565	$ 3,707	$ 3,853	$ 4 004	$ 4 159	$ 4 318	$ 5 650	$ 5 819	$ 5,994	$ 6,174	$ 6,359	$
Less Total Interest Expense	$	$	$	$	$	$	$	$	$	$ -	$ -	$ -
Less Total Principal Repayment	$	$	$	$	$	$	$	$	$	$	$	$
Less Increase in Working Capital	$ 74	$ 94	$ 97	$ 100	$ 103	$ 106	$ 109	$ 112	$ 116	$ 119	$	$
Less Change in Debt Reserve Fund	$	$	$	$	$	$	$	$	$	$ -	$	$
Operating Cash Flow	$ 9 881	$ 10 124	$ 10 393	$ 10 669	$ 10 954	$ 11 248	$ 10 384	$ 10 695	$ 11 016	$ 11 346	$ 11 810	$ -
Less Capital Cost/Sale Price	$	$	$	$	$	$	$	$	$	$	$	$
Net Cash Flow After Investments	$ 9 881	$ 10 124	$ 10 393	$ 10 669	$ 10 954	$ 11 248	$ 10 384	$ 10 695	$ 11 016	$ 11 346	$ 11 810	$
Plus Loan Draws	$	$	$	$	$	$ -	$	$	$	$ -	$	$ -
Net Cash Flow After Debt Financing	$ 9 881	$ 10 124	$ 10 393	$ 10 669	$ 10 954	$ 11 248	$ 10 384	$ 10 695	$ 11 016	$ 11 346	$ 11 810	$ -
Plus Equity Draws	$	$	$ -	$	$	$	$ -	$ -	$ -	$	$ -	$
Net Cash Flow For Equity Distribution	$ 9 881	$ 10 124	$ 10 393	$ 10 669	$ 10 954	$ 11 248	$ 10 384	$ 10 695	$ 11 016	$ 11 346	$ 11 810	$ -
Return on Equity												
Cash Available for Equity Distribution	$ 9 881	$ 10 124	$ 10 393	$ 10 669	$ 10 954	$ 11 248	$ 10 384	$ 10 695	$ 11 016	$ 11 346	$ 11 810	$ -
Less Equity Paid in Cash	$	$	$	$	$	$	$	$	$	$	$	$
Equity Participants Cash Flow	$ 9 881	$ 10,124	$ 10,393	$ 10 669	$ 10,954	$ 11,248	$ 10,384	$ 10,695	$ 11,016	$ 11 346	$ 11,810	$

Return on Equity	**18%**
Net Present Value @ Discount Rate	
10%	**$20,391**
12%	**$13,114**
14%	**$7,608**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Pay Back Year	2010				-							-

B

Romania IPP Assessment (inside-the-fence example)
Cash Flow Statement
(Thousand Dollars)

Year Ending	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Plus Operating Revenues	$	$	$ 60 596	$ 62 414	$ 64 287	$ 66 215	$ 68 202	$ 70 248	$ 72 355	$ 74 526	$ 76 762
Less Operating Expenses	$	$	$ 45 081	$ 46 434	$ 47 827	$ 49 261	$ 50 739	$ 52 261	$ 53 829	$ 55 444	$ 57 107
Cash From Operations	$	$ -	$ 15 515	$ 15 981	$ 16 460	$ 16 954	$ 17 463	$ 17 986	$ 18 526	$ 19 082	$ 19 654
Plus Interest on Reserve Fund	$	$ -	$ 325	$ 324	$ 324	$ 324	$ 324	$ 324	$ 324	$ 324	$ 324
Less Income Taxes	$	$	$ 922	$ 1 084	$ 1 463	$ 1 869	$ 2 303	$ 2 768	$ 3 267	$ 4 275	$ 4,850
Less Total Interest Expense	$	$ -	$ 6 913	$ 6 913	$ 6,309	$ 5,644	$ 4,912	$ 4,108	$ 3 223	$ 2 249	$ 1 178
Less Total Principal Repayment	$	$ -	$ -	$ 6,045	$ 6 650	$ 7 315	$ 8 046	$ 8 851	$ 9 736	$ 10 709	$ 11,780
Less Increase in Working Capital	$	$ -	$ -	$ 133	$ 137	$ 141	$ 146	$ 150	$ 155	$ 159	$ 164
Less Change in Debt Reserve Fund	$	$	$ (21)	$	$	$	$	$	$	$	$ (6,479)
Operating Cash Flow	$	$	$ 8 026	$ 2 129	$ 2 225	$ 2 309	$ 2 380	$ 2 434	$ 2 471	$ 2 014	$ 8 485
Less Capital Cost/Sale Price	$ 45,370	$ 53,389	$	$	$	$	$	$	$	$	$
Net Cash Flow After Investments	$ (45 370)	$ (53 389)	$ 8 026	$ 2 129	$ 2 225	$ 2 309	$ 2 380	$ 2 434	$ 2 471	$ 2 014	$ 8 485
Plus Loan Draws	$ 31 759	$ 37 372	$	$	$	$	$	$	$	$	$
Net Cash Flow After Debt Financing	$ (13,611)	$ (16 017)	$ 8,026	$ 2 129	$ 2 225	$ 2 309	$ 2 380	$ 2 434	$ 2 471	$ 2 014	$ 8 485
Plus Equity Draws	$ 13 611	$ 16 017	$	$	$	$	$	$	$ -	$	$ -
Net Cash Flow For Equity Distribution	$	$	$ 8 026	$ 2 129	$ 2 225	$ 2 309	$ 2 380	$ 2,434	$ 2,471	$ 2,014	$ 8,485
Return on Equity											
Cash Available for Equity Distribution	$	$	$ 8 026	$ 2 129	$ 2 225	$ 2 309	$ 2 380	$ 2,434	$ 2 471	$ 2,014	$ 8,485
Less Equity Paid in Cash	$ 13 611	$ 16 017	$	$	$	$	$	$ -	$	$	$
Equity Participants Cash Flow	$ (13,611)	$ (16,017)	$ 8,026	$ 2 129	$ 2 225	$ 2,309	$ 2 380	$ 2,434	$ 2 471	$ 2 014	$ 8 485

Return on Equity	**18%**
Net Present Value @ Discount Rate	
10%	**$30,664**
12%	**$19,787**
14%	**$11,556**
Pay Back Year	

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Romania IPP Assessment (inside-the-fence example)
Cash Flow Statement
(Thousand Dollars)

B

Year Ending	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Plus Operating Revenues	$ 79 065	$ 81 436	$ 83 880	$ 86,396	$ 88,988	$ 91,657	$ 94 407	$ 97 239	$ 100 157	$ 103 161	$ 106 256	$
Less Operating Expenses	$ 58 821	$ 60 585	$ 62 403	$ 64 275	$ 66 203	$ 68 189	$ 70 235	$ 72 342	$ 74 512	$ 76 748	$ 79 050	$
Cash From Operations	$ 20 244	$ 20 851	$ 21 477	$ 22 121	$ 22 785	$ 23 468	$ 24 172	$ 24 897	$ 25 644	$ 26 414	$ 27,206	$ -
Plus Interest on Reserve Fund	$	$	$	$	$	$	$	$	$	$	$	$
Less Income Taxes	$ 5,355	$ 5 568	$ 5 787	$ 6 012	$ 6 244	$ 6 484	$ 8 460	$ 8 714	$ 8 976	$ 9 245	$ 9 522	$ -
Less Total Interest Expense	$	$	$	$	$	$	$	$	$	$	$	$ -
Less Total Principal Repayment	$	$	$	$	$	$	$	$	$	$	$	$ -
Less Increase in Working Capital	$ 142	$ 174	$ 179	$ 185	$ 190	$ 196	$ 202	$ 208	$ 214	$ 220	$	$ -
Less Change in Debt Reserve Fund	$	$	$	$	$	$	$	$	$	$	$	$
Operating Cash Flow	$ 14 746	$ 15 109	$ 15 511	$ 15 924	$ 16 350	$ 16 789	$ 15 510	$ 15 976	$ 16 455	$ 16 949	$ 17 684	$ -
Less Capital Cost/Sale Price	$ -	$	$	$	$	$	$	$	$ -	$	$	$ -
Net Cash Flow After Investments	$ 14 746	$ 15 109	$ 15 511	$ 15 924	$ 16 350	$ 16 789	$ 15 510	$ 15 976	$ 16 455	$ 16 949	$ 17 684	$ -
Plus Loan Draws	$	$	$	$	$	$ -	$	$	$	$	$	$ -
Net Cash Flow After Debt Financing	$ 14 746	$ 15 109	$ 15 511	$ 15 924	$ 16 350	$ 16 789	$ 15 510	$ 15 976	$ 16 455	$ 16 949	$ 17 684	$ -
Plus Equity Draws	$	$	$	$	$	$	$	$	$	$	$	$
Net Cash Flow For Equity Distribution	$ 14 746	$ 15 109	$ 15 511	$ 15 924	$ 16 350	$ 16 789	$ 15 510	$ 15 976	$ 16 455	$ 16 949	$ 17 684	$
Return on Equity												
Cash Available for Equity Distribution	$ 14 746	$ 15 109	$ 15 511	$ 15 924	$ 16 350	$ 16 789	$ 15 510	$ 15 976	$ 16 455	$ 16 949	$ 17,684	$ -
Less Equity Paid in Cash	$	$	$	$	$	$ -	$	$	$	$ -	$ -	$ -
Equity Participants Cash Flow	$ 14,746	$ 15 109	$ 15 511	$ 15 924	$ 16 350	$ 16 789	$ 15 510	$ 15 976	$ 16 455	$ 16,949	$ 17,684	$ -

Return on Equity	**18%**
Net Present Value @ Discount Rate	
10%	**$30,664**
12%	**$19,787**
14%	**$11,556**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Pay Back Year	2010					-				-		

Romanıa IPP Assessment (ınsıde-the-fence example)

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Cash Flow Statement

(Thousand Dollars)

C

Year Endıng	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Plus Operatıng Revenues	$	$	$ 60 626	$ 62 444	$ 64 318	$ 66 247	$ 68 235	$ 70 282	$ 72 390	$ 74 562	$ 76 799
Less Operatıng Expenses	$	$ -	$ 45 349	$ 46 709	$ 48 110	$ 49 554	$ 51 040	$ 52 572	$ 54 149	$ 55 773	$ 57 446
Cash From Operatıons	$	$	$ 15 277	$ 15 735	$ 16 207	$ 16 694	$ 17 194	$ 17 710	$ 18 241	$ 18 789	$ 19 352
Plus Interest on Reserve Fund	$	$	$ 330	$ 328	$ 328	$ 328	$ 328	$ 328	$ 328	$ 328	$ 328
Less Income Taxes	$	$	$ 794	$ 954	$ 1 333	$ 1 739	$ 2 173	$ 2 638	$ 3 137	$ 4 150	$ 4 726
Less Total Interest Expense	$	$	$ 6 990	$ 6 990	$ 6 379	$ 5 706	$ 4 967	$ 4 153	$ 3 258	$ 2 274	$ 1 191
Less Total Prıncıpal Repayment	$	$ -	$	$ 6 112	$ 6 723	$ 7 396	$ 8 135	$ 8 949	$ 9 844	$ 10,828	$ 11 911
Less Increase ın Workıng Capıtal	$	$	$	$ 133	$ 137	$ 141	$ 145	$ 149	$ 154	$ 159	$ 163
Less Change ın Debt Reserve Fund	$	$	$ (49)	$	$	$	$	$	$	$	$ (6 551)
Operating Cash Flow	$	$	$ 7 872	$ 1 874	$ 1 963	$ 2 040	$ 2 102	$ 2 148	$ 2 176	$ 1 706	$ 8 239
Less Capıtal Cost/Sale Prıce	$ 45 877	$ 53,978	$	$	$	$	$	$	$ -	$	$ -
Net Cash Flow After Investments	$ (45 877)	$ (53 978)	$ 7 872	$ 1 874	$ 1 963	$ 2 040	$ 2 102	$ 2 148	$ 2 176	$ 1 706	$ 8 239
Plus Loan Draws	$ 32,114	$ 37 784	$	$	$	$	$	$	$	$	$
Net Cash Flow After Debt Fınancing	$ (13,763)	$ (16,193)	$ 7 872	$ 1 874	$ 1 963	$ 2 040	$ 2 102	$ 2 148	$ 2 176	$ 1 706	$ 8 239
Plus Equıty Draws	$ 13 763	$ 16 193	$	$	$	$	$	$	$	$	$
Net Cash Flow For Equity Dıstrıbution	$	$ 0	$ 7 872	$ 1 874	$ 1 963	$ 2 040	$ 2 102	$ 2 148	$ 2 176	$ 1 706	$ 8 239
Return on Equıty											
Cash Avaılable for Equıty Dıstrıbutıon	$	$ 0	$ 7 872	$ 1 874	$ 1 963	$ 2 040	$ 2 102	$ 2 148	$ 2 176	$ 1 706	$ 8 239
Less Equıty Paıd ın Cash	$ 13 763	$ 16 193	$	$	$	$	$	$	$	$	$ -
Equıty Partıcıpants Cash Flow	$ (13 763)	$ (16 193)	$ 7 872	$ 1 874	$ 1,963	$ 2,040	$ 2 102	$ 2 148	$ 2 176	$ 1,706	$ 8 239
Return on Equıty	**18%**										
Net Present Value @ Dıscount Rate											
10%	**$28,473**										
12%	**$17,860**										
14%	**$9,842**										
Pay Back Year			-						-	-	-

Romania IPP Assessment (inside-the-fence example)
Cash Flow Statement
(Thousand Dollars)

C

Year Ending	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Plus Operating Revenues	$ 79 103	$ 81 476	$ 83 920	$ 86 438	$ 89,031	$ 91,702	$ 94 453	$ 97 286	$ 100 205	$ 103 211	$ 106 307	$
Less Operating Expenses	$ 59 170	$ 60,945	$ 62,773	$ 64 656	$ 66 596	$ 68 594	$ 70,652	$ 72,771	$ 74 955	$ 77 203	$ 79 519	$ -
Cash From Operations	$ 19 933	$ 20 531	$ 21,147	$ 21 781	$ 22 435	$ 23 108	$ 23 801	$ 24,515	$ 25 250	$ 26 008	$ 26 788	$
Plus Interest on Reserve Fund	$	$	$	$	$	$ -	$	$ -	$ -	$	$	$ -
Less Income Taxes	$ 5 232	$ 5 441	$ 5 657	$ 5,879	$ 6,107	$ 6 343	$ 8 330	$ 8 580	$ 8 838	$ 9 103	$ 9 376	$
Less Total Interest Expense	$	$	$	$	$	$	$	$	$ -	$	$	$
Less Total Principal Repayment	$	$	$	$	$	$	$	$	$ -	$ -	$	$
Less Increase in Working Capital	$ 141	$ 173	$ 178	$ 184	$ 189	$ 195	$ 201	$ 207	$ 213	$ 219	$ -	$
Less Change in Debt Reserve Fund	$	$	$	$	$	$	$	$	$	$ -	$	$
Operating Cash Flow	$ 14 560	$ 14 917	$ 15 312	$ 15 719	$ 16 138	$ 16 570	$ 15 270	$ 15 728	$ 16 200	$ 16 686	$ 17 412	$ -
Less Capital Cost/Sale Price	$	$	$	$	$	$ -	$	$	$ -	$ -	$	$ -
Net Cash Flow After Investments	$ 14 560	$ 14 917	$ 15 312	$ 15 719	$ 16,138	$ 16 570	$ 15 270	$ 15 728	$ 16 200	$ 16 686	$ 17,412	$
Plus Loan Draws	$	$	$	$	$	$	$	$	$ -	$	$	$
Net Cash Flow After Debt Financing	$ 14 560	$ 14 917	$ 15 312	$ 15 719	$ 16 138	$ 16 570	$ 15 270	$ 15 728	$ 16 200	$ 16 686	$ 17 412	$ -
Plus Equity Draws	$	$	$	$	$	$	$	$	$ -	$	$	$
Net Cash Flow For Equity Distribution	$ 14 560	$ 14 917	$ 15 312	$ 15 719	$ 16 138	$ 16 570	$ 15 270	$ 15 728	$ 16 200	$ 16 686	$ 17 412	$
Return on Equity												
Cash Available for Equity Distribution	$ 14 560	$ 14 917	$ 15 312	$ 15 719	$ 16 138	$ 16 570	$ 15 270	$ 15 728	$ 16 200	$ 16,686	$ 17,412	$ -
Less Equity Paid in Cash	$	$	$	$	$	$ -	$	$	$ -	$	$	$
Equity Participants Cash Flow	$ 14,560	$ 14 917	$ 15 312	$ 15 719	$ 16 138	$ 16 570	$ 15 270	$ 15,728	$ 16 200	$ 16 686	$ 17 412	$

Return on Equity	**18%**	
Net Present Value @ Discount Rate		
10%	**$28,473**	
12%	**$17,860**	
14%	**$9,842**	
Pay Back Year		2011 -

Romania IPP Assessment (inside-the-fence example)
Cash Flow Statement
(Thousand Dollars)

D

Year Ending	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Plus Operating Revenues	$	$	$ 100,541	$ 103 558	$ 106 664	$ 109 864	$ 113 160	$ 116 555	$ 120 052	$ 123 653	$ 127 363
Less Operating Expenses	$	$	$ 74 320	$ 76 550	$ 78 846	$ 81 212	$ 83 648	$ 86 157	$ 88 742	$ 91 404	$ 94 146
Cash From Operations	$	$	$ 26 221	$ 27 008	$ 27 818	$ 28 653	$ 29 512	$ 30 398	$ 31 310	$ 32 249	$ 33 216
Plus Interest on Reserve Fund	$	$	$ 565	$ 561	$ 561	$ 561	$ 561	$ 561	$ 561	$ 561	$ 561
Less Income Taxes	$	$ -	$ 1 361	$ 1 635	$ 2,285	$ 2 980	$ 3 724	$ 4 521	$ 5 377	$ 7 115	$ 8 103
Less Total Interest Expense	$	$	$ 11 970	$ 11 970	$ 10 923	$ 9 772	$ 8 505	$ 7 112	$ 5 580	$ 3 894	$ 2 040
Less Total Principal Repayment	$	$	$	$ 10 467	$ 11 513	$ 12 665	$ 13 931	$ 15,324	$ 16 857	$ 18 543	$ 20 397
Less Increase in Working Capital	$	$	$	$ 221	$ 228	$ 234	$ 241	$ 249	$ 256	$ 264	$ 272
Less Change in Debt Reserve Fund	$	$ -	$ (82)	$	$	$	$	$ -	$ (0)	$ 0	$ (11,218)
Operating Cash Flow	$	$	$ 13 538	$ 3 277	$ 3 431	$ 3,563	$ 3 672	$ 3 752	$ 3 801	$ 2 994	$ 14 184
Less Capital Cost/Sale Price	$ 78,871	$ 92 124	$ -	$	$	$	$	$	$	$	$ -
Net Cash Flow After Investments	$ (78 871)	$ (92 124)	$ 13 538	$ 3 277	$ 3 431	$ 3 563	$ 3 672	$ 3 752	$ 3 801	$ 2 994	$ 14 184
Plus Loan Draws	$ 55 210	$ 64 487	$	$	$	$	$ -	$ -	$	$	$
Net Cash Flow After Debt Financing	$ (23 661)	$ (27 637)	$ 13,538	$ 3 277	$ 3,431	$ 3,563	$ 3 672	$ 3 752	$ 3 801	$ 2 994	$ 14 184
Plus Equity Draws	$ 23 661	$ 27 637	$ -	$	$	$	$	$ -	$ -	$	$
Net Cash Flow For Equity Distribution	$	$	$ 13 538	$ 3 277	$ 3 431	$ 3 563	$ 3 672	$ 3 752	$ 3,801	$ 2 994	$ 14 184
Return on Equity											
Cash Available for Equity Distribution	$	$	$ 13 538	$ 3 277	$ 3 431	$ 3 563	$ 3 672	$ 3 752	$ 3 801	$ 2 994	$ 14,184
Less Equity Paid in Cash	$ 23 661	$ 27 637	$ -	$	$	$	$	$ -	$	$	$ -
Equity Participants Cash Flow	$ (23 661)	$ (27,637)	$ 13,538	$ 3,277	$ 3 431	$ 3 563	$ 3 672	$ 3 752	$ 3,801	$ 2 994	$ 14,184

Return on Equity	**18%**
Net Present Value @ Discount Rate	
10%	**$49,309**
12%	**$31,051**
14%	**$17,256**
Pay Back Year	

Romania IPP Assessment (inside-the-fence example)
Cash Flow Statement
(Thousand Dollars)

D

Year Ending	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Plus Operating Revenues	$ 131 184	$ 135 119	$ 139,173	$ 143 348	$ 147 649	$ 152 078	$ 156 640	$ 161 340	$ 166 180	$ 171 165	$ 176 300	$
Less Operating Expenses	$ 96 971	$ 99 880	$ 102,876	$ 105 963	$ 109 142	$ 112 416	$ 115 788	$ 119 262	$ 122 840	$ 126 525	$ 130 321	$
Cash From Operations	$ 34 213	$ 35 239	$ 36 297	$ 37 385	$ 38 507	$ 39 662	$ 40 852	$ 42 078	$ 43 340	$ 44 640	$ 45 979	$ -
Plus Interest on Reserve Fund	$	$	$	$	$	$	$	$	$ -	$	$	$ -
Less Income Taxes	$ 8 969	$ 9 328	$ 9 698	$ 10 080	$ 10,472	$ 10 876	$ 14 298	$ 14 727	$ 15 169	$ 15 624	$ 16,093	$
Less Total Interest Expense	$	$	$	$	$	$	$	$	$ -	$	$	$ -
Less Total Principal Repayment	$	$	$	$	$	$	$	$	$ -	$	$	$
Less Increase in Working Capital	$ 234	$ 288	$ 297	$ 306	$ 315	$ 325	$ 334	$ 344	$ 355	$ 365	$	$
Less Change in Debt Reserve Fund	$	$	$	$	$	$	$	$	$ -	$	$	$ -
Operating Cash Flow	$ 25 010	$ 25 623	$ 26 301	$ 27 000	$ 27 720	$ 28 461	$ 26 220	$ 27 006	$ 27 816	$ 28 651	$ 29 887	$ -
Less Capital Cost/Sale Price	$	$	$	$	$	$ -	$	$	$ -	$	$	$ -
Net Cash Flow After Investments	$ 25,010	$ 25 623	$ 26 301	$ 27 000	$ 27,720	$ 28 461	$ 26 220	$ 27 006	$ 27 816	$ 28 651	$ 29 887	$
Plus Loan Draws	$	$	$	$	$	$	$	$	$ -	$	$	$ -
Net Cash Flow After Debt Financing	$ 25 010	$ 25 623	$ 26 301	$ 27 000	$ 27 720	$ 28 461	$ 26 220	$ 27 006	$ 27 816	$ 28 651	$ 29 887	$
Plus Equity Draws	$	$	$	$	$	$	$	$ -	$ -	$ -	$ -	$ -
Net Cash Flow For Equity Distribution	$ 25 010	$ 25 623	$ 26 301	$ 27 000	$ 27 720	$ 28 461	$ 26 220	$ 27 006	$ 27 816	$ 28 651	$ 29 887	$
Return on Equity												
Cash Available for Equity Distribution	$ 25 010	$ 25 623	$ 26 301	$ 27 000	$ 27 720	$ 28,461	$ 26 220	$ 27 006	$ 27 816	$ 28 651	$ 29 887	$
Less Equity Paid in Cash	$	$	$	$	$	$	$	$	$ -	$	$	$ -
Equity Participants Cash Flow	$ 25 010	$ 25 623	$ 26 301	$ 27 000	$ 27 720	$ 28 461	$ 26 220	$ 27 006	$ 27 816	$ 28,651	$ 29 887	$ -

Return on Equity	**18%**												
Net Present Value @ Discount Rate													
10%	**$49,309**												
12%	**$31,051**												
14%	**$17,256**												
Pay Back Year			2011							-			-

Appendix D — Engineering and Cost Assumptions

The following is a list of documents/programs used in the development of cost estimates and engineering assumptions for the four IPP cases evaluated in this study

Total Installed Cost
Installed cost estimates and major equipment costs were provided by GTPRO data Total installed cost includes all inside-the fence costs including switchyard Each major inside-the-fence cost component was assumed to represent a certain percentage of total installed costs The breakout is as follows

- Engineering, Procurement and Construction (EPC) @ 73%
- Start-up @2%
- Construction Management @ 5%
- Contingency @ 10%
- Risk @ 5%
- Fee @ 5%

Plant Construction Period
24 months

Plant Heat Rate
All plant heat rates are based on LHV of natural gas No adjustment was made for a decline in plant operating efficiency over time

Plant Availability
A 90% availability rate was assumed based on operating results detailed in reports on combined cycle plants

Plant Equipment and Configuration Assumptions
The table shown below illustrates the equipment used and plant configuration for each of the 4 IPP cases evaluated in this report

Case	Electric Capacity	Steam Capacity	Installed Cost ($/kW)	Heat Rate (kJ/kWh)[1]	Plant Configuration
A	70 MW	65 TPH	$610	8,432	1 x Gas Turbine, 1 x Steam Turbine, and 1 x HRSG (Siemens Equipment)
B	150 MW	130 TPH	$423	8,285	1 x Gas Turbine, 1 x Steam Turbine, and 1 x HRSG (GE equipment)
C	170 MW	0 TPH	$410	7,216	1 x Gas Turbine, 1 x Steam Turbine, and 1 x HRSG (GE Equipment)
D	300 MW	0 TPH	$373	6,866	1 x Gas Turbine, 1 x Steam Turbine, and 1 x HRSG (GE Equipment)

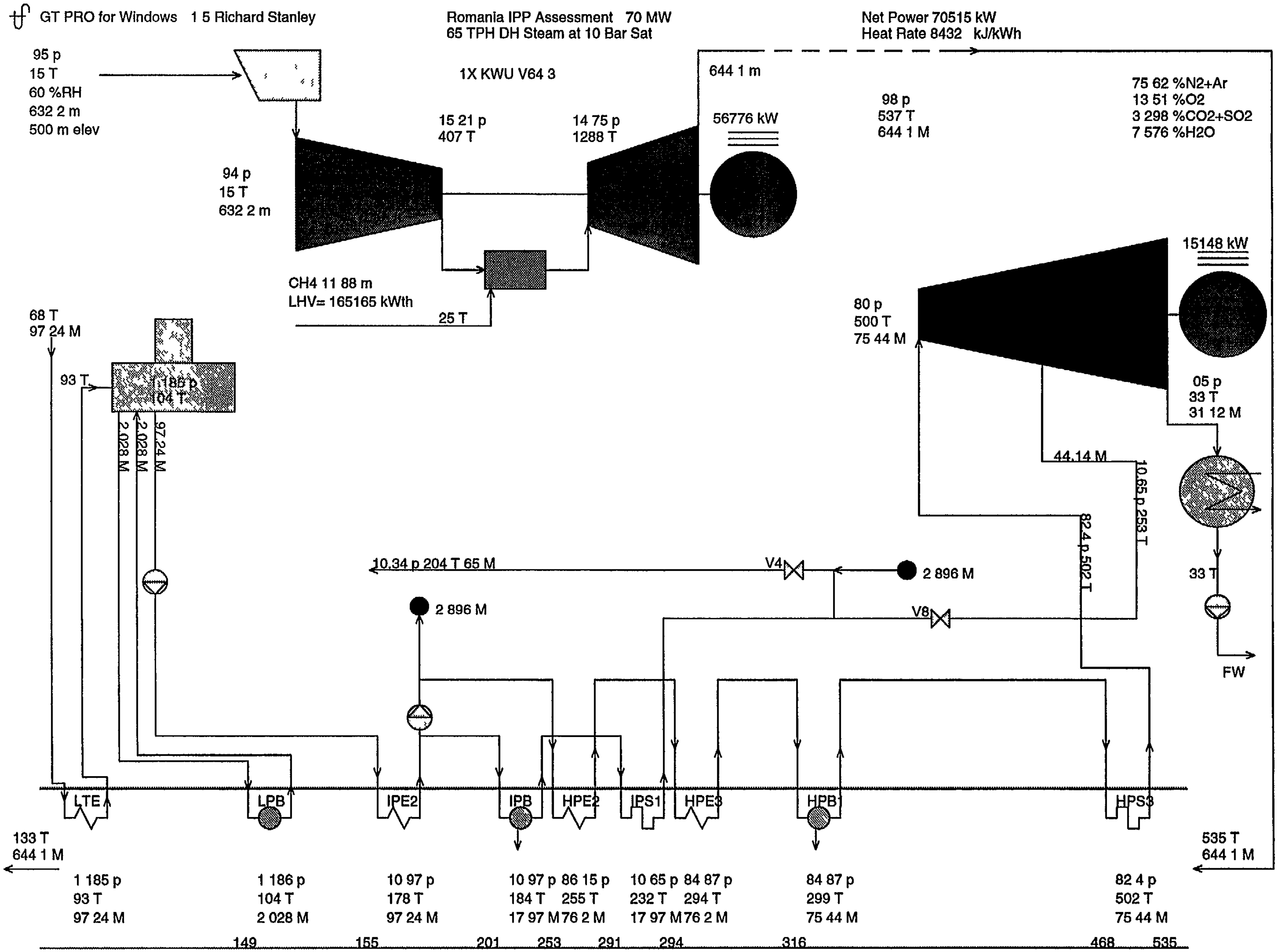
[1] Plant heat rates for Cases A and B do not reflect efficiency gains from CHP generation

For the purposes of this study, it is assumed that these IPP plants will be base-loaded units operating at full capacity

Plant Diagrams

Plant diagrams for IPP cases are shown on the following pages

(A)

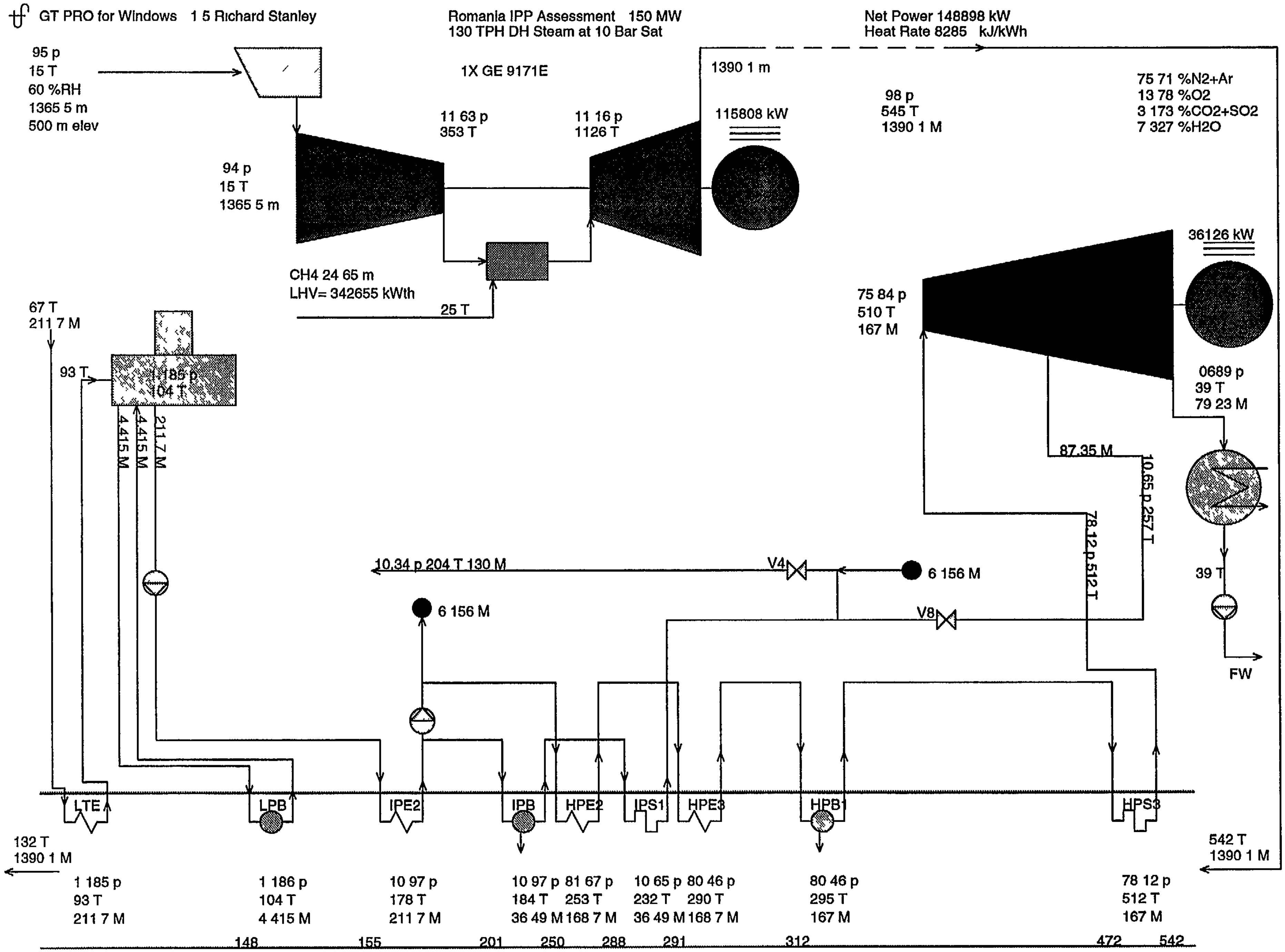


p[bar] T[C] m[t/h]

54 10 02 1998 12 48 57 file=C \GTPM150\70CCDH GTP

64

23



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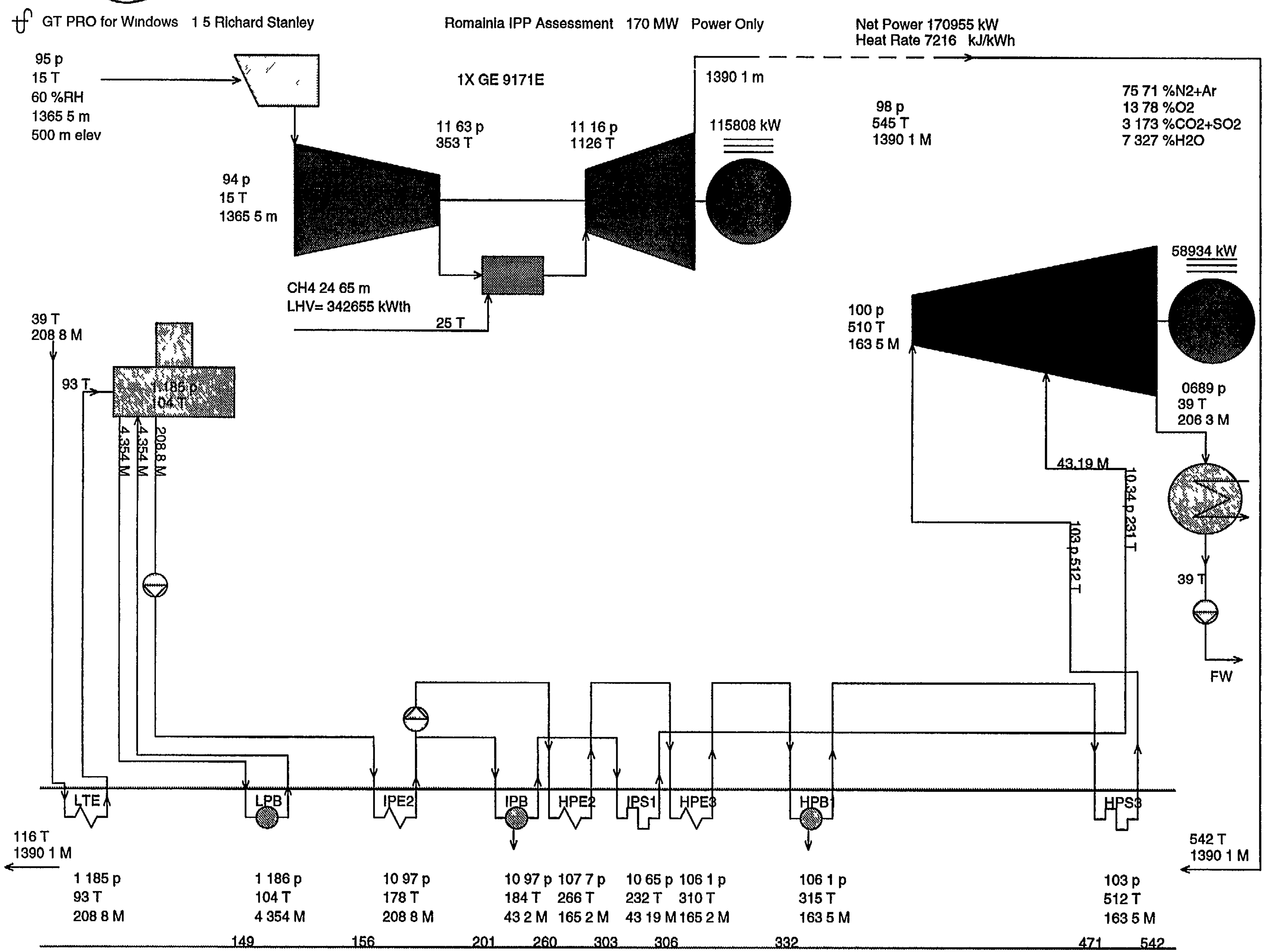
45



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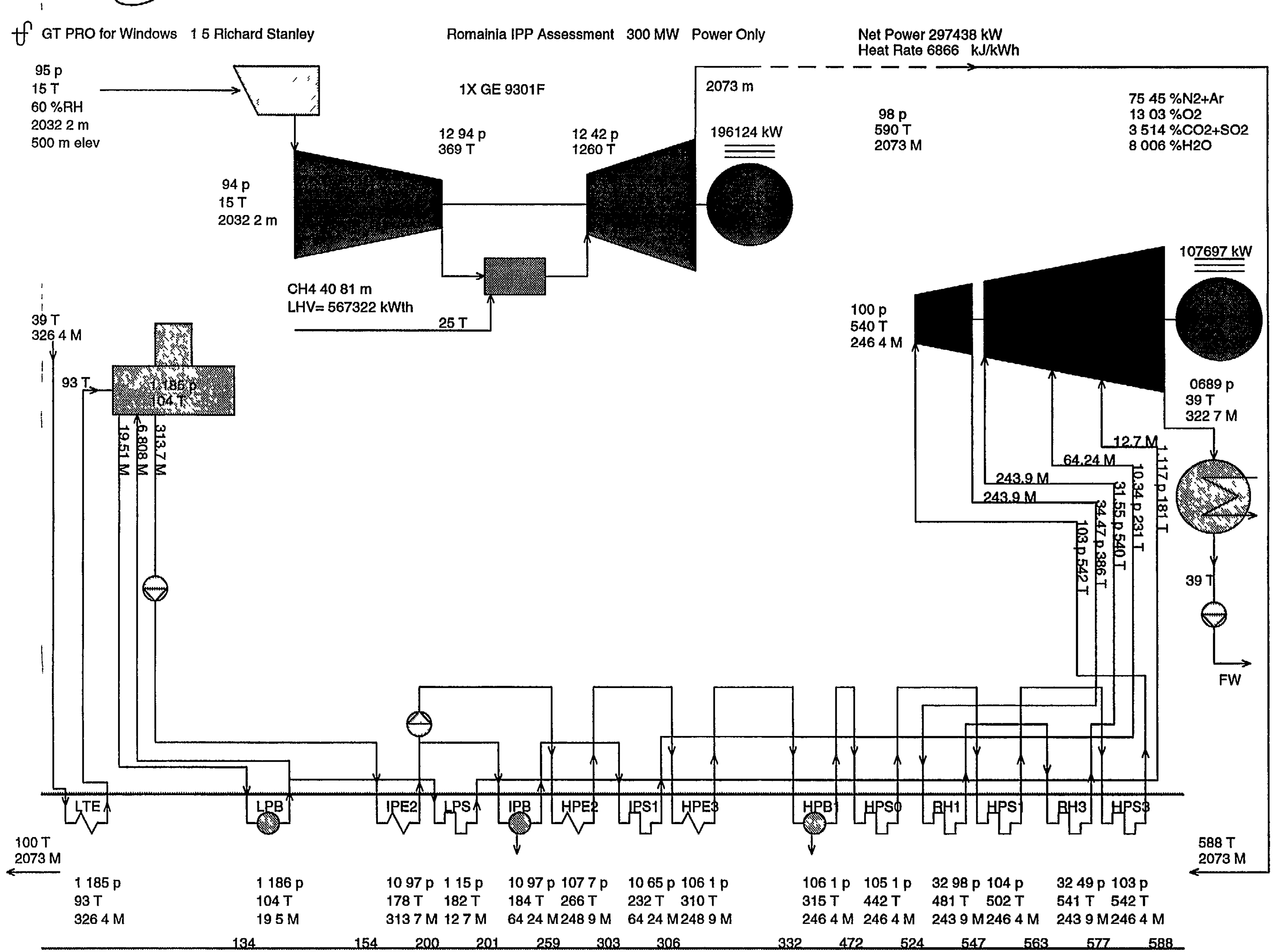

p[bar] T[C], m[t/h]

54 10 02 1998 11 40 47 file=C \GTPM150\300CC GTP